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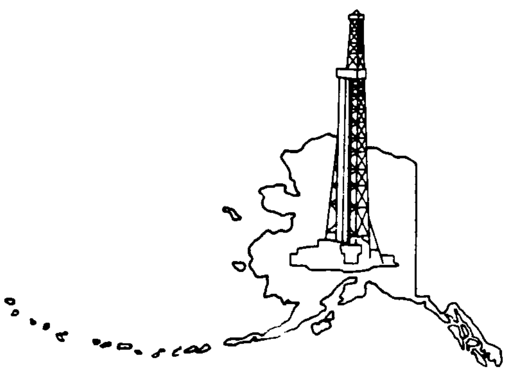
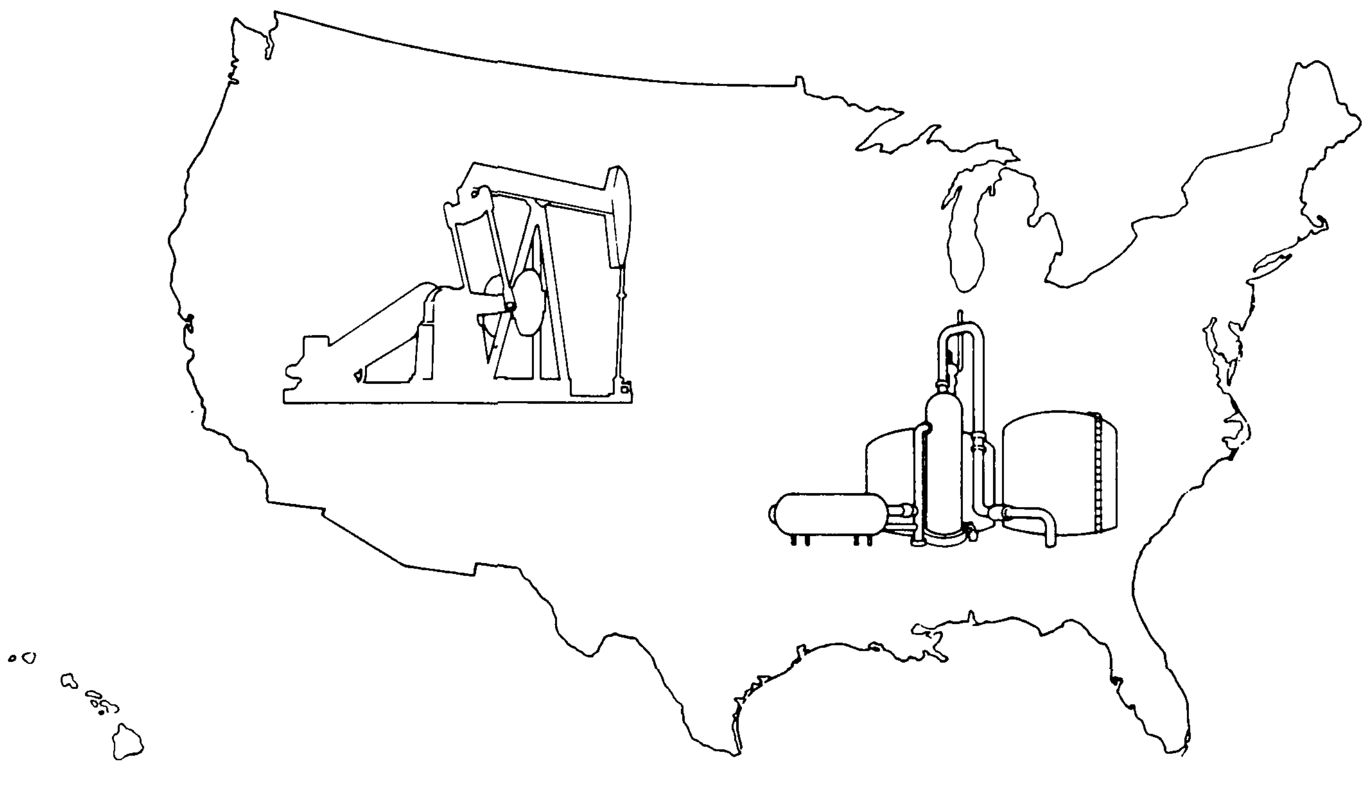
Report to Congress

Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy

Volume 3 of 3
Appendices

A-Summary of State Oil and Gas Regulations
B-Glossary of Terms for Volume 1
C-Damage Case Summaries





REPORT TO CONGRESS

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Office of Solid Waste and Emergency Response
Washington, D.C. 20460

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APPENDIX A

SUMMARY OF STATE OIL AND GAS REGULATIONS

ALABAMA

INTRODUCTION

Alabama produced 8,486,000 barrels of oil, 11,392,000 barrels of condensate, and 137 x 10^9 cubic feet of gas in 1984. Production was from 760 oil wells, 509 conventional gas wells, and 184 coalbed methane wells. Thirteen percent of conventional oil and gas wells and 52 percent of coalbed methane wells are strippers.

Alabama began limited regulation of oil and gas activities in 1946. Regulations for disposal of drilling wastes were adopted in 1973. Regulations and/or administrative codes have been revised continually over the past 40 years.

REGULATORY AGENCIES

Four agencies regulate oil and gas activity in Alabama. They are:

- Alabama State Oil and Gas Board;
- Alabama Department of Environmental Management;
- U.S. Bureau of Land Management; and
- U.S. Army Corps of Engineers.

The Alabama State Oil and Gas Board is "charged with preventing the waste of Alabama's oil and gas resources and protecting the correlative rights of owners." In carrying out its mandate, the Board regulates all oil and gas operations, from the issuance of drilling permits through the production phase. The Oil and Gas Board has the authority to issue permits for Underground Injection Control (UIC) Class II wells. The various permitting requirements and conditions of the Oil and Gas Board are detailed in the Board's Administrative Code.

The Alabama Department of Environmental Management (ADEM) has the authority to issue permits for all UIC wells other than Class II. The Department of Environmental Management also has National Pollutant Discharge Elimination System (NPDES) authority. The Oil and Gas Board and the Department of Environmental Management operate under a 1979 Memorandum of Agreement that requires the Board to forward information regarding actual or proposed discharges to the Department of Environmental Management.

The U. S. Bureau of Land Management's authority and regulations for Federally-held mineral rights are discussed separately in the section on Federal agencies. (See Volume 1, Chapter VII.) The U.S. Forest Service retains surface rights (and usually coordinates stipulations with the Bureau of Land Management) in Federal forests and grasslands.

STATE RULES AND REGULATIONS

Drilling

Drilling pits are permitted by the Oil and Gas Board. The Board has certain construction requirements to ensure the integrity of these pits. Pits are closed by dewatering (see below), then backfilling, leveling, and compacting.

No pits are permitted in Alabama's coastal wetlands. The Department of Environmental Management prohibits the use of pits in wetlands in order to ensure the protection of surface or ground-water resources. Many of the wetland areas in Alabama fall within the jurisdiction of the Alabama Coastal Area Management Program, which is enforced by ADEM. The Certificate of Consistency, which must be issued by ADEM before a permit can be granted by the Board, requires use of portable aboveground tanks for any well drilled in the coastal area.

Drilling muds and pit fluids may be disposed of in one of three ways. They may be injected into a formation below underground sources of drinking water. They may be transported to a drilling mud treatment (recycling) facility. In non-wetlands, the fluids may be applied to the land surface or into an approved landfill if:

- The chloride concentration is less than 500 mg/L;
- The Oil and Gas Board is properly notified;
- The landowner provides written approval;
- It is a one-time-only application; or
- There will be no discharge to a surface body of water.

These activities are permitted by the Oil and Gas Board prior to allowing disposal of fluids.

Production Waters

Class II injection wells are used for (1) the disposal of waters produced in association with oil and/or natural gas, (2) the disposal of nonhazardous wastewaters that may be generated during the operation of a gas plant, (3) the enhanced recovery of oil or natural gas, or (4) the storage of liquid hydrocarbons at standard temperature and pressure. Currently, all of Alabama's 250 Class II injection wells are used for disposal purposes or for the enhancement of oil or natural gas production.

According to Rule 400-1-5-.04, "Immediately following the initiation of production in any field or pool, all salt water shall be disposed of into an approved underground formation or otherwise disposed of as approved by the Supervisor where such salt water cannot damage or pollute underground sources of drinking water, oil, gas or other minerals." The permitting of Class II injection wells in Alabama is a two-step process. Step 1, obtaining approval to drill or convert a well for injection purposes, includes a review of all well construction within a one-quarter mile radius of the proposed injection well, along with the submission of data concerning the construction of the proposed injection well, analyses and estimated volumes of fluids to be injected, anticipated injection pressures, known or calculated fracture pressure of the proposed injection interval, and the lowermost depth of fresh water. All injections will be made through tubing anchored by a packer unless otherwise approved by the Oil and Gas Supervisor. In addition, the operator must provide proof that the injection casing is adequately cemented in order to prevent vertical fluid migration, and must test the injection casing at a pressure equal to two-tenths of the depth of the mid-point of the injection interval, but not to exceed 1,500 psi.

Following completion of the Board's Step 1 requirements, the applicant may receive approval to start injection. Once injection begins, the operator must submit monthly reports on injection volumes, injection pressures, and the casing-tubing annulus pressures. The injection pressure and the casing-tubing annulus pressure must be recorded daily or computed on an average daily basis from weekly measurements. Also, chemical analyses of injected fluids must be submitted on an annual basis, and a pressure test should be performed at least once every 5 years.

Produced waters from coalbed methane wells are an exception to the injection requirement. EPA has advised Alabama that coalbed methane production is not covered under the Federal onshore oil and gas regulations. Produced waters from coalbed methane wells may be allowed to accumulate in pits and settle. They would then be discharged directly into live streams. The Department of Environmental Management stipulates that operators must obtain permits for such discharges and requires that such discharges meet a 600 mg/L in-stream limit.

Plugging/Abandonment

Plugging is required after 6 months, but wells may be approved for temporary abandonment if future utility can be shown. Thereafter, well status must be reported every 6 months.

When plugging, cement plugs of not less than 100 feet should be placed above any producing formation, from 50 feet below to 50 feet above the base of freshwater strata, and from 50 feet below to 50 feet above the base of the surface casing. A 25-foot plug should be near the surface and a steel plate should be placed over the casing stub. Intervals between the plugs must be filled with mud-laden fluid.

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Personal Communication:

Treena Pizner, Alabama Department of Environmental Management (205) 271-7850.

ALASKA

INTRODUCTION

Alaska produced 681,309,821 barrels of oil and 316 x 10^9 cubic feet of gas in 1986. During 1986, 608,225,599 barrels of water and 1,066 x 10^9 cubic feet of gas were injected into producing formations for enhanced oil recovery.

Alaska ranked second in U.S. oil production, but 23rd in the number of production wells (1,191 wells) in 1986. It ranked 8th in U.S. gas production and 24th in the number of producing gas wells (104 wells).

In 1986, oil and gas in Alaska were produced from two development regions, the South Central region (including Cook Inlet and the Kenai Peninsula) and the North Slope region. The State contains other prospective regions, but to date no discoveries have been made there. Approximately 663,738,428 barrels of oil and 123 x 10^9 cubic feet of gas were produced from the North Slope in 1986 from two fields (Kuparuk and Prudhoe). The Endicott Field (Duck Island) will begin production in early 1988. Production at the Milue Point unit is currently suspended for economic reasons.

The Kenai Peninsula produced mostly gas with little associated produced water. In 1986, fields in the South Central region produced 17,571,393 barrels of oil and 193 x 10^9 cubic feet of gas.

REGULATORY AGENCIES

The eight agencies that regulate oil and gas activities in Alaska are:

- Alaska Oil and Gas Conservation Commission;
- Alaska Department of Environmental Conservation;
- U.S. Bureau of Land Management;
- Alaska Department of Natural Resources;
- Alaska Department of Fish and Game;
- U.S. Army Corps of Engineers;
- U.S. EPA Region X; and
- U.S. Fish and Wildlife Service.

The Alaska Oil and Gas Conservation Commission (AOGCC) regulates the production and conservation of oil and gas in Alaska and is responsible for issuing permits for drilling. The Commission checks well casings to prevent contamination of water and has primacy for the Class II injection wells. Under Title 31 of the Alaska Statutes, the Commission has the status of an independent quasi-judicial agency. Its three commissioners, appointed by the Governor, must include an expert in petroleum engineering and an expert in petroleum geology.

The Alaska Department of Environmental Conservation (DEC) is the primary pollution control agency within the State government. The Department regulates and permits solid waste disposal, wastewater discharges, and air contaminant emissions. It issues State discharge permits for oil and gas drilling and production operations. The Department also regulates hazardous wastes, oil spill control, and the subsurface disposal of nonhazardous oil and gas wastes (which are not regulated as Class II wastes). Since Alaska does not have responsibility for the NPDES program, DEC coordinates with EPA Region X, which administers the NPDES program in Alaska.

The U.S. Bureau of Land Management is responsible for all oil and gas activity on Federal and Indian lands (under 43 CFR 3160). There are 370 million acres of land in Alaska, of which more than half are under Federal ownership. There are 150 producing oil and gas wells on Federal leases. Regulatory processes for oil and gas operations are covered in the Onshore Oil and Gas Order No. 1. More information on BLM regulations can be found in the section on Federal programs. (See Volume 1, Chapter VII.)

The Alaska Department of Natural Resources issues surface and subsurface oil and gas leases on State land. Leasing stipulations address environmental concerns, such as requiring that reserve pits be rendered impermeable, at lease award. The Department also approves plans of operation for all oil and gas activity on State lands. The approval letter contains site-specific stipulations developed through inter-agency review. In addition, the Department conducts field inspections of operations and abandonments.

Under Section 404 of the Clean Water Act, the U.S. Army Corps of Engineers is responsible for issuing permits for dredge and fill activities on wetlands defined as part of the waters of the United States, and U.S. EPA has review responsibility for such permits. Several other State and Federal agencies also have comment and/or concurrence responsibilities on the Federal permits. Since much of Alaska's drilling and production activity, including that on the North Slope, takes place on wetlands, all pads, roads, and facilities have 404 permits. The Corps of Engineers requires all reserve pits to be rendered impermeable.

The U.S. Fish and Wildlife Service, in addition to having comment responsibility on 404 permits, has been conducting research related to the permitted discharge of drilling fluids to the tundra wetlands. The research project currently in progress is designed to determine the deleterious effect of the discharge on wildlife in the wetlands, especially to waterfowl.

STATE RULES AND REGULATIONS

New revisions to the regulations for the handling of drilling and production wastes (18 AAC 60) in Alaska were adopted by the Department of Environmental Conservation in June 1987. These amendments impose more stringent requirements on the management of reserve pits and drilling wastes.

Reserve Pits

The management and disposal of drilling wastes primarily involve the proper operation and closure of the reserve pit used during drilling operations. The reserve pit often provides the permanent disposal site for solids or solidified wastes from the drilling operation. Although in exploratory drilling, reserve pits may often be used and closed in a single season, on the North Slope many are in continuous use because of the directional drilling of multiple wells from a single pad. There are, however, a variety of ways in which drilling wastes are ultimately disposed of, such as subsurface injection. (In 18 AAC 60.910, "drilling wastes" are defined as including "drilling muds, cuttings, hydrocarbons, brine, acid, sand, and emulsions of mixtures of fluids produced from and unique to the operation or maintenance of a well.")

State statutes require permits for solid waste disposal facilities; however, prior to 1982, few solid waste permits were issued for reserve pits. As early as 1982, it became policy to require permits for all currently active and new pits in the Cook Inlet area. The same policy was applied on the North Slope beginning in 1985.

Under 20 AAC 25.047, administered by the AOGCC, reserve pits are required "for the reception and confinement of drilling fluids and cuttings, to facilitate the safety of the drilling operation, and to prevent contamination of ground water and damage to the surface environment." The general construction requirement is that the pits must be rendered "impervious."

The new DEC regulations impose specific construction and performance requirements for reserve pits. The particular requirements depend on factors such as the proximity of surface water or ground water that is used for drinking water, the proximity of an existing or developing population, and whether the pit is being built in an area of continuous permafrost. For example, a reserve pit being constructed in a nonpermafrost region within 100 feet of a surface water body used for drinking water would require a double liner, leachate collection (if there is no fluid management plan), site inspection, and monitoring. A reserve pit in a permafrost region not adjacent to water supplies or population would require a containment structure (possibly lined) designed to prevent the escape of wastes from the reserve pit, site inspection, a fluid management plan, and monitoring.

Under 20 AAC 25.047, administered by the AOGCC, upon termination of operations related to a particular reserve pit, "the operator shall proceed with diligence to dispose of and solidify in place all pumpable fluids, and shall leave the reserve pit in a condition that does not constitute a hazard to ground water." Under 18 AAC 60 and 18 AAC 72, administered by the DEC, solid waste permits are required for closure and wastewater permits are needed for all discharges. Pits must be closed within 12 months after the final drilling wastes have been disposed of in the pit.

Disposal from Reserve Pits

Reserve pit fluids on the North Slope may be disposed of through injection in dedicated wells. In the Kenai area there have been several permits for centralized disposal of oil field wastes. One of these permitted disposal facilities was operated by an independent concessionaire on Kenai Borough-owned land, but DEC canceled the permit because contaminants were found in monitoring wells.

DEC has issued general permits for discharges to the tundra, for annular injection of reserve pit fluids, and for dedicated injection wells that are not Class II wells, and issues occasional specific permits for road application. Injection into dedicated Class II wells is permitted by the Oil and Gas Conservation Commission. Annular injection is allowed under the permit-to-drill issued by AOGCC.

Surface Discharge to Tundra

DEC issued a seasonal general permit on May 12, 1986 (expired September 30, 1986) for discharges onto the tundra from reserve pits containing "produced waters, drilling fluids and cuttings, boiler blowdown, rig washing fluids, workover fluids, completion fluids, excess fluids from blowouts and drill pad runoff." Only those pits that had received no discharges or placements of any materials into the pit since August 1, 1985, were eligible (that is, pits that had gone through a 1-year freeze-thaw cycle to precipitate contaminants). Further, pits must have no visible sheen on the surface. Operators must notify DEC 2 weeks prior to any discharge, and include information on volumes and analyses for salinity, settleable solids, arsenic, and chromium. Written approval must be received from DEC prior to the discharge. The permit applies only to discharges of the clarified supernatant from the pits. The maximum drawdown is 18 inches from pit bottom at point of withdrawal to prevent solids carry-over. Other management practices, such as injection, must be used for further drawdown. Effluents must be monitored during discharge. The effluent limitations for 1986 were:

COD	200 mg/L
pH	6.0 8.5(or within 0.5 of receiving water)
Salinity	3 parts/thousands
Settleable solids	1 mg/L
Oil and grease	15 mg/L
Aromatic hydrocarbons	10 ug/L
Arsenic	0.05 mg/L
Barium	1 mg/L
Cadmium	0.01 mg/L
Chromium	0.05 mg/L
Lead	0.05 mg/L
Mercury	0.002 mg/L.

These limitations were to be reevaluated prior to issuance of the 1987 general permit. Limitations are also being evaluated for copper, zinc, aluminum, and boron. The process of reevaluation after 1985 led to the elimination of an effluent limitation for manganese in the 1986 general permit. DEC figures in the information sheet with the 1986 general permit indicate that approximately 36 million gallons of liquid were discharged from 43 reserve pits in 1985, 35 of which exceeded limitations. Sixteen of these pits, however, exceeded only the limitation for manganese, which is found at naturally high levels in waters on the slope.

Surface Discharge to Roads

Permits for road applications of reserve pit fluids, used for dust control during the summer, are issued to individual applicants. Two permits issued to facilities of one company for 1986 were valid from May 15th to December 31st, but specified that discharges must be between June 1st and August 31st unless DEC determined sufficient thaw existed to prevent puddling or runoff.

Unlike discharges to the tundra, road application permits do not require that the reserve pit fluids go through a 1-year freeze-thaw cycle before disposal. Application is specifically designated for particular roads and pads. Spraying is prohibited when the surfaces are already wet. Spraying is to be made no closer than 3 feet from the edge of the shoulder of any pad or road to prevent spraying onto adjacent areas. Compliance with effluent limitations is to be determined at the edge of the road or pad. The required limitations are the same as those for discharge to the tundra, except for the range for pH (6 to 9). Sampling and monitoring reports are required.

Annular Disposal

Reserve pit wastes are frequently injected down the annulus either of the well being drilled or of another well on the pad. A general permit for annular disposal for the North Slope was issued by DEC for the period of August 6, 1985, to April 30, 1987. The permit applies to the discharge of "fluids produced from the drilling, servicing or testing of oil and gas exploration, development, service and stratigraphic test wells, including but not limited to drilling fluids, rig washwater, completion fluids, formation fluids, reserve pit meltwaters and domestic wastewaters...."

Discharge must occur below the permafrost zone; the minimum depth must be 1,000 feet. No discharge must be into any zone containing total dissolved solids (TDS) of less than 3,000 ppm. Operators must notify DEC at least 2 weeks before beginning injection, and must include information on volumes and types of material being injected, the zone and depth of the injection, and the method to be used to seal the injection zone at the completion of disposal. Written approval must be received from DEC. A report must be submitted after closure of the well, stating volumes and types of liquids injected, well location, well designations, date and time of injections, and depth of injection zones.

This option may require that the operator perform annual maintenance on the well to preserve the permafrost.

Injection Wells

The Oil and Gas Conservation Commission has responsibility for Class II UIC wells. The Commission permits the disposal of both oil field waste fluids and produced waters into wells dedicated to disposal of oil field wastes (20 AAC 25.252), and approves injection into wells for enhanced recovery (20 AAC, Article 5). While the numbers continually change, current figures provided in February and March 1987 were 17 disposal wells (14 North Slope, 3 Kenai) and 387 enhanced recovery wells.

Since more water is injected for enhanced recovery in Alaska than is produced with oil and gas production, produced waters are injected into disposal wells only when they are geographically distant from any enhanced recovery operation. Additional water for enhanced recovery is drawn from both Cook Inlet and the Arctic Ocean.

Injection for enhanced recovery may be carried out under area injection orders (20 AAC 25.460). The Commission may issue orders permitting injection on an area basis, rather than for each individual well, if the wells are essentially similar; are within the same field, site, or similar area; are operated by a single operator; and are used to inject other than hazardous waste.

Reserve pit fluids may be injected into dedicated disposal wells or, in some instances, returned down the annulus to formation.

Injection wells must be cased with safe and appropriate casing, tubed to prevent leakage, and cemented to protect oil, gas, and freshwater strata. At application, information must be provided on all wells within one-quarter mile of the injection well that penetrate the injection zone. Adequate evidence must be provided that a proposed injection well will not cause or increase fractures in overlying strata, which could allow injected or formatic.. liquids to enter freshwater strata. (Freshwater aquifers may be exempted from the restrictions affecting them if they currently do not and cannot in the future serve as sources of drinking water; are between 3,000 and 10,000 mg/L TDS but cannot be reasonably expected to supply a public water system; or if they are too contaminated for economic or technologically practical recovery.)

Injection wells must be equipped with tubing and packer or other equipment that would isolate pressure to the injection interval. Wells must undergo pressure tests for mechanical integrity before operation. The test must run for 30 minutes at 1,500 psi or 0.25 psi/ft times the vertical depth of the casing shoe, whichever is greater (but must not exceed 70 percent of the minimum yield strength of the casing), with a maximum pressure decline of 10 percent. Thereafter, mechanical integrity must be demonstrated by the operator by monitoring the pressure in the casing-tubing annulus during actual injection. The monitored pressure must be reported monthly.

At present, two applications are pending with the EPA for permits for dedicated, Class I, disposal wells on the North Slope, one for the Prudhoe Bay Unit and one for the Endicott Unit. These wells will be for restricted oil and gas development wastes.

Plugging/Abandonment

All wells that have been permitted on a property must be abandoned within 1 year following cessation of the operator's oil and gas activity within the field where the wells are located. Any well that is not completed after drilling must be abandoned or suspended before the drilling equipment is removed.

The Commission may approve suspension of a well if it has future productive or service use, and if there is a justifiable reason for the suspension (e.g., unavailability of production or marketing facilities). The operator of a suspended well must set a bridge plug 200 to 300 feet below the casing head and cap with 100 linear feet of cement. Additional plugging requirements for a suspended well would be determined by the Commission on a site-specific basis.

Abandoned wells must be plugged to prevent movement of fluid into or between freshwater and hydrocarbon sources. Uncased portions of a well must be cased to keep fluids in original strata; cement plugs must be placed from 50 feet below to 100 feet above hydrocarbon strata, and from 150 feet below to 50 feet above the base of the lowest freshwater stratum.

Uncased and cased portions of the wellbore must be segregated; various cementing method/plug placement combinations may be used (e.g., plug from 100 feet below to 100 feet above the casing shoe, using the displacement method).

Cased portions of the wellbore must be plugged with cement to confine hydrocarbons and fresh water to the original strata. Perforated intervals must be plugged by one of several methods (e.g., by extending cement plugs from 100 feet below to 50 feet above the base and from 50 feet below to 100 feet above the top of each interval, or by placing a mechanical bridge with a 75-foot cement cap 50 feet over the interval), as must casing stubs within the outer casing (plug from 100 feet above to 100 feet below the stub, bridge plug 25 feet over the stub with a 75-foot cap, or downsqueeze 150 feet of cement through the retainer with an additional 50-foot plug).

Surface plugs must seal annular openings in communication with the open hole, and a 150-foot cement plug must extend to within 5 feet of grade elevation.

Cements used for plugging within permafrost zones must be designed to set before freezing and have low heat of hydration. Muds equaling or exceeding the density of mud used to drill each interval should fill the intervals between plugs.

Final abandonment of the wells and drill sites must also be approved by the Alaska Department of Natural Resources if the site is on State land.

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Personal Communications:

William Barnwell, Alaska Oil and Gas Conservation Commission (907) 279-1433.

Michael Frank, Alaska Attorney General's Office, Natural Resources Division (907) 276-3550.

Douglas Lowery, Alaska Department of Environmental Conservation (907) 452-1714.

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ARIZONA

INTRODUCTION

Arizona produced 214,000 barrels of oil and 225 MMCF of gas in 1984. Production was from 26 oil wells and 5 gas wells. Approximately 655 barrels of produced waters are produced in the State per day.

REGULATORY AGENCIES

The five agencies that regulate the oil and gas industry in Arizona are:

- Arizona Oil and Gas Conservation Commission;
- U.S. Bureau of Land Management;
- U.S. Bureau of Indian Affairs;
- Arizona Department of Health and Safety; and
- EPA, Region IX.

The Bureau of Land Management (BLM) has the authority to issue oil and gas drilling permits for Federal minerals. Where Indian mineral rights prevail, oil and gas activity may be governed by both the BLM and the Bureau of Indian Affairs.

The Arizona Oil and Gas Conservation Commission reviews all oil and gas drilling applications and is primarily responsible for approving and enforcing oil and gas activities. The Oil and Gas Commission's regulations pertain to the construction, location, and operation of onsite drilling and production activities.

Arizona does not have NPDES or UIC program primacy. The Department of Health and Safety coordinates with EPA's Region IX for any surface water discharge or underground injection permits. Region IX administers the UIC program; there are no discharges from oil and gas facilities.

STATE RULES AND REGULATIONS

Drilling

Reserve pits receive drilling fluids and muds, drill cuttings, and any waters produced during drilling. The pits are allowed to evaporate before closure, and then are filled.

Production

All waters produced during the production phase are reinjected, for either enhanced recovery or disposal. To drill an injection well, permit approval is required from both EPA Region IX and the Commission. The casing and cementing requirements in the Arizona State regulations are general, requiring "safe or adequate casing or tubing in order to prevent leakage," cemented and set to prevent damage to gas, oil, or freshwater strata. Surface casing is required to be pressure tested at 600 psi for 30 minutes, with a maximum allowable drop of 10 percent in pressure.

Plugging/Abandonment

The regulations do not specify a time limit for plugging a well after production ceases. Decisions are made on a case-by-case basis. In the case of a dry hole, plugging must take place within 60 days after the cessation of drilling, unless permission for temporary abandonment is granted by the Commission.

When a well is plugged, a 50-foot cement plug must be placed immediately above each producing formation, and a continuous cement plug must be placed through, and to 50 feet above and below all freshwater strata. A 20-foot cement plug must be placed at or near the surface of the well. Intervals between plugs must be filled with heavy mud. An uncased hole must be plugged with heavy mud up to the base of the surface string, at which point a 50-foot plug must be placed in and out of the bottom of the surface pipe.

References

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Oil and Gas Conservation Commission. 1982. Arizona Administrative Code Chapter 7, Article 1. Oil, Gas, and Helium.

Personal Communications:

Lyndon Hammon, NPDES Permits Section Manager, Arizona Department of Health and Safety. September 29, 1986 (602) 257-2262.

Nate Lau, Director of the UIC Division, EPA Region IX. September 28, 1986 (415) 974-0893.

ARKANSAS

INTRODUCTION

Arkansas produced 19,715,691 barrels of oil and 194,483 MM cubic feet of gas in 1985. Production is from 9,490 oil wells and 2,492 gas wells. The State is divided into two geographical districts. The Arcoma Basin, located in the northwest corner of the State, produces 99 percent natural gas on a volume basis. The Mississippi Embayment in southeastern Arkansas produces approximately 90 percent oil and 10 percent gas.

REGULATORY AGENCIES

The two agencies that regulate oil and gas activity in Arkansas are:

- Arkansas Oil and Gas Commission; and
- Arkansas Department of Pollution Control and Ecology.

The Arkansas Oil and Gas Commission regulates industry practices regarding drilling and production activities of oil and gas wells under the authority of Act 105 of 1939 (the "Oil and Gas Act"), Act 937 of 1979, and Act 523 of 1981. Act 105 created the Oil and Gas Commission and authorized it to prevent the waste of oil and gas resources and the pollution of freshwater supplies by oil, gas, or salt water. Act 937 authorized the Commission to prevent waste in produced water production. Act 523 amended the "Oil and Gas Act" to authorize the Oil and Gas Commission to "acquire primary enforcement responsibility either singularly or jointly with the Department of Pollution Control and Ecology for the control of underground injection under the applicable provisions of the Safe Drinking Water Act." Drilling and production practices are regulated under the "General Rules and Regulations" of the Commission (Order No. 2-39). The General Rules and Regulations do not address all aspects of industry practices, and refer the reader to "special rules pertaining to individual oil, gas, or salt water fields and pools." Special rules of any nonemergency nature require a public hearing, and are provided for in Rules A-2 and B-38 of the General Rules and Regulations.

The Arkansas Department of Pollution Control and Ecology (ADPCE) regulates pollution generally, or pollution specifically related to oil and gas drilling and production wastes, under authority of Act 472 of 1949 (the "Arkansas Water and Air Pollution Control Act"), Act 120 of 1961, Act 254 of 1969, and Act 743 of 1975. Act 472 provided authority to ADPCE to establish pollution standards and industrial discharge limits for State waters. Act 120 included "wells" within the definition of waters of the State, and made it a violation to cause pollution in waters of the State. Act 254 provided a tax penalty for operators allowing salt water to escape a lease, and required ADPCE to identify the source of pollution and to take steps to eliminate it if the chloride level in any stream exceeded 250 ppm. Act 743 of 1975 provided ADPCE with jurisdiction to permit disposal of pollutants into wells.

The principal regulations of ADPCE related to oil and gas drilling and production wastes are found in Regulation No. 1, "Regulation for the Prevention of Pollution by Salt Water and Other Oil Field Wastes Produced by Wells in New Fields or Pools." The regulation was promulgated on October 13, 1958, pursuant to the authority provided by Act 472.

ADPCE is currently considering revisions to Regulation No. 1 that would be modeled on Louisiana State Order No. 29-B. As of the start of 1987, however, the timing and outcome of the effort were uncertain.

Arkansas has primacy for both the NPDES program and the UIC program. The NPDES program is administered by ADPCE. A Memorandum of Agreement (March 25, 1982) governs the division of authority between ADPCE and the Oil and Gas Commission with respect to underground injection wells, but there continues to be some disagreement between the two agencies as to what the Agreement actually allows or requires.

Under the Agreement, ADPCE has primary responsibility for Class I, III, IV, and V injection wells, except for bromine-related brine disposal wells. AOGC is given "administrative management responsibility for the issuance of construction and operating permits for Class II and Class V bromine-related disposal wells. AOGC shall be responsible for enforcement in respect to all Class II wells." AOGC is further described as responsible for well integrity and the migration of wastes from the injection strata into actual or potential drinking water aquifers.

The Memorandum also notes, however, the statutory overlap of jurisdiction that it was intended to resolve. The degree to which this issue is still unresolved is reflected in the introduction, during the current session of the legislature, of a bill drafted by counsel for the Commission that would have given the Commission exclusive authority with respect to Class II wells, while repealing all portions of statutes giving ADPCE any claim to such jurisdiction. The bill failed to get out of committee.

The result of this conflict is that operators do not always comply, or believe they need to comply, with all of the requirements of ADPCE. According to information provided by both the Department and the Commission, operators in the gas fields in the northern part of the State tend to follow the Department's requirements, while those in the older oil fields in the south frequently fail to apply for ADPCE permits or follow their requirements.

STATE RULES AND REGULATIONS

Drilling

The Oil and Gas Commission does not have any specific regulations governing the construction or management of reserve pits or the disposal of drilling wastes, nor does Regulation No. 1 of ADPCE impose any requirements on reserve pits. Typical practices include onsite disposal in unlined reserve pits or landspreading in the vicinity of the pit.

ADPCE, however, has been sending out letters of authorization intended to serve as informal permits that stipulate management practices for reserve pits and disposal of drilling wastes. Many of the provisions required by the letter are those the Department would like to include in a proposed revision of Regulation No. 1. The lack of specific regulations containing the provisions in the letter, however, has resulted in uneven compliance with these requirements by operators. The letter lists conditions that the Department of Pollution Control and Ecology expects to be followed during drilling operations pertaining to reserve pit construction, pit fluid and drilling mud disposal, and drill site reclamation.

Under the letter's requirements, all earthen pits must be lined with a synthetic liner (20 mils thick) or a clay liner (18 to 24 inches thick), and must maintain at least 2 feet of freeboard. Pits must be reclaimed to grade and seeded within 60 days after the drilling rig has been removed from the site. Reserve pit fluids can be disposed of only by ADPCE permitted disposal services.

The letter of authorization also states that completion fluids high in total dissolved solids, such as KCl, should be kept separate from the contents of the reserve pit, and recommends that a lined pit be used for this purpose.

Production

Rules C-7 and C-8 of the General Rules and Regulations define the means by which salt water produced from oil and gas wells can be discharged into subsurface formations for disposal or enhanced recovery. The Oil and Gas Commission states that it will consult the State Geological Survey and the State Board of Health, when reviewing an application to inject salt water, in order to protect freshwater supplies.

Wells for disposal and enhanced recovery are to be cased and cemented "in such manner that damage will not be caused to oil, gas or freshwater resources." Injection pressure must be limited to ensure that fractures are not propagated in the confining zones. Injection must be through tubing set on a packer. Information must be provided by the applicant on all wells or dry holes within one-half mile of the new or converted injection well.

Section 4 of Regulation No. 1 forbids discharging salt water from any oil or gas well in a manner whereby the salt water might come in contact with "any of the waters of the State, whether by natural drainage, seepage, overflow, or otherwise." Other sections of Regulation No. 1 require the well operator to obtain a permit for a waste disposal system that prevents the wastes from contacting State waters. The regulation provides two alternatives for saltwater disposal: (1) subsurface discharge in disposal wells constructed in accordance with the Rules and Regulations of the Arkansas Oil and Gas Commission, and (2) surface discharge into lined earthen pits. Currently, only subsurface disposal is permitted.

The letter of authorization issued by the Arkansas Department of Pollution Control and Ecology states that salt water produced any time during the lifetime of a well will remain the responsibility of the production company. and "shall be stored in a plastic or fiberglass tank above ground and resting on a concrete pad."

Offsite Disposal

Disposal of reserve pit fluids and drilling mud requires a permit from the Arkansas Department of Pollution Control and Ecology. The permit stipulates that the disposal company must provide an analysis of the pit fluids and drilling mud, the amount hauled, and its final destination. A disposal company that is permitted to land apply pit fluid and drilling mud near the well must provide the Department with a copy of the landowner's agreement as well as an analysis of the wastes. An analysis of pit fluid will include tests for chlorides and pH, and a drilling mud analysis will contain tests for chromium, zinc, chlorides, and pH.

Plugging/Abandonment

Wells that are not completed as commercially productive after drilling must be abandoned and plugged before the drilling equipment is released from the drilling operation. No time limitation is established in the regulations, however, for temporary abandonment of a properly cased well.

When plugging, a 100-foot cement plug must be placed above each producing stratum, or a bridge plug may be used. A cement plug of

100 feet must be placed 50 feet below the base of the freshwater stratum if surface casing is not cemented below that stratum; if it is cemented, a 100-foot cement plug should be placed inside the base of the surface casing. A plug should be set at the surface of the ground in such a way as not to interfere with cultivation. Intervals between plugs should be filled with heavy mud-laden fluid.

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CALIFORNIA

INTRODUCTION

California produced 423,900,000 barrels of oil and 493 billion x 10^9 cubic feet of gas in 1985. California ranked fourth in U.S. oil production and sixth in U.S. gas production. Production was from 55,079 producing oil wells and 1,566 producing gas wells. Approximately 55 percent of the oil production is attributed to enhanced recovery.

REGULATORY AGENCIES

A number of agencies regulate oil and gas activity in California, including:

- California Department of Conservation, Division of Oil and Gas;
- California Water Resources Control Board and the nine Regional Water Quality Control Boards;
- California Department of Health Services;
- California Air Resources Board and the county or regional Air Pollution Control Districts;
- State Lands Commission;
- California Coastal Commission;
- Local government agencies;
- U.S. Bureau of Land Management; and
- U.S. Department of Energy.

The Division of Oil and Gas of the California Department of Conservation, created in 1915, issues permits for the drilling, reworking, and abandonment of oil and gas wells. Under authority delegated by EPA, the Division also issues UIC permits for Class II injection wells. As part of its responsibilities, the Division ensures that the drilling and operation of such wells do not endanger fresh ground-water strata.

The California Water Resources Control Board is generally responsible for protecting the waters of the State and for preserving all present and anticipated beneficial uses of these waters. EPA has delegated authority to issue NPDES permits to the Water Resources Control Board. This responsibility is implemented through nine Regional Water Quality Control Boards, which issue Waste Discharge Requirements (California's NPDES permits) for point sources of water pollution. The Water Resources Control Board has the authority to adopt statewide water quality policy and water quality control plans for regional boards to follow.

The regional boards must, at a minimum, implement requirements as strict as those of the State board; however, they have autonomy to develop more stringent requirements within their regions. All discharges of drilling wastes or produced waters to surface impoundments or surface waters are subject to the permitting authority of the regional boards. Under a Memorandum of Understanding between the Regional Water Quality Control Boards and the Division of Oil and Gas, the regional boards also have the responsibility for reviewing permits written by the Division of Oil and Gas to ensure the incorporation of the concerns of the regional boards.

The California Department of Health Services is responsible for the regulation of hazardous wastes. The Department determines which waste streams and constituents are hazardous under California's laws, including determinations as to the hazardousness of drilling fluids and muds. The Department is also responsible for the regulation of the injection wells into which hazardous wastes are being injected. Further, the Department of Health Services shares with the Regional Water Quality Control Boards the responsibility for regulating hazardous waste landfills and surface impoundments.

For wells on State-owned, onshore lands, the State Lands Commission has joint responsibility with the Division of Oil and Gas. Their responsibilities are expressed in the provisions of the lease terms.

The California Department of Fish and Game, while not a permitting agency for drilling projects, provides comments and recommendations on methods to mitigate any problems that oil and gas operations may create for fish and wildlife. The Department of Fish and Game coordinates State operations involving spills that affect fish and wildlife.

Local Air Pollution Control Districts issue permits to operate equipment that emits pollutants into the atmosphere. The equipment includes steam generators used for enhanced oil recovery projects.

The California Coastal Commission issues permits for any development proposed within the coastal zone. This zone extends from the State's 3-mile seaward limit to 1,000 yards inland. Oil and gas projects within this area would need permits, although there are provisions for exemptions.

Cities and counties also issue land use permits for oil and gas operations. Generally, a condition of their permits requires that an operator comply with the regulations of the Division of Oil and Gas.

The Bureau of Land Management (BLM) approves approximately 400 oil and gas drilling permits per year on Federal lands and provides permits for wells for reinjection of produced waters. Since operators of these wells must meet the requirements of the State as well as BLM, they are subject to dual permitting. In 1985, there were 6,200 oil, gas, and injection wells on Federal lands. The oil and gas wells produced about 22.4 million barrels of water per month, with most going to reinjection and some to evaporation percolation ponds.

The Department of Energy manages the Elk Hills Naval Petroleum Reserves. In 1985, these fields produced approximately 86,000 barrels of water, 128,000 barrels of oil, and 184 billion cubic feet of gas per day. Produced waters have been reinjected or disposed of in earthen sumps, but the Department of Energy has been managing a transition to disposal only in injection wells.

STATE RULES AND REGULATIONS

Drilling

Under Article 9 of Title 22 of the California Administrative Code, drilling fluids and drilling muds are listed as wastes that come under the provisions of the regulations for hazardous wastes if they contain a hazardous material. Most muds actually in use in California do not fall under this provision, however. The Department of Health Services has prepared a list (available to operators on request) of additives and fluids that are nonhazardous if used according to the manufacturers' recommendations. The Department will also review test data submitted by companies on new muds or fluids when requested to do so, in order to determine if they are nonhazardous.

Discharges of drilling muds and cuttings that do not contain halogenated solvents into onsite sumps are specifically excluded from the requirements affecting "Discharges of Waste to Land" (Subchapter 15, Chapter 3, Title 23) under the jurisdiction of the Regional Water Quality

Control Boards, provided that the operator takes appropriate measures at the conclusion of drilling operations. The operator must either "(1) remove all wastes from the sump or (2) remove all free liquid from the sump and cover solid and semisolid wastes, provided that representative sampling of the sump contents after liquid removal shows residual solid wastes to be nonhazardous."

Drilling pits may or may not need to be lined or sealed depending on their location. While the Regional Water Quality Control Boards do not prescribe pit construction conditions, the conditional use permit that a driller obtains from each county may detail the pit requirements. If the fluids contain hazardous materials, the pits would have to have liners.

On Federal lands, drilling fluids are left in the sump until completion of the well, after which drilling fluids are hauled to a Class II disposal site for oil field wastes.

Before drilling a well, operators must file an indemnity bond with the Division of Oil and Gas to ensure that the applicant complies with the permit requirements and properly abandons or completes the well. After proper abandonment or completion, the Division releases the bond.

Produced Waters

Produced waters may be reinjected for enhanced recovery or disposal, discharged on the surface for beneficial use, placed in lined sumps for evaporation or unlined sumps for evaporation and percolation, or disposed of in sewer systems. In some cases, produced waters ultimately disposed of in sumps are first discharged into watercourses, which carry the salt water to the sumps. The impact and legality of this practice are currently under review. The approximate percentages of produced water disposed of by each method are:

Evaporation in percolation sumps	18%
Evaporation in lined sumps	6%
Disposal in sewer systems	2%
Surface disposal (beneficial)	18%
Injection for enhanced recovery	41%
Injection for disposal	15%.

Surface Discharge for Beneficial Use

In cases where the quality of the water is sufficient for beneficial use for irrigation, livestock, and/or wildlife, produced waters may be permitted for discharge into surface waters (principally into irrigation canals, dry ditches, and ephemeral streams). There are at least 12 such permits in the Fresno office of the Central Valley Regional Water Quality Control Board. Discharge permit limits include the following maximum values:

Oil and grease	35 mg/L
Chlorides	200 mg/L
Boron	1 mg/L
Electrical conductivity	1,000 umhos.

Sewer Disposal

The small percentage that goes to sewer systems is predominantly within the Los Angeles County Sanitation District. Production waters entering such sewers must meet applicable pretreatment standards, including a maximum oil and grease content of 75 mg/L, and limits on heavy metals, cyanide, chlorinated hydrocarbons, and sulfides. There is no pretreatment limit for chloride.

Pits

Regulation of all saltwater sumps is under the jurisdiction of the Regional Water Quality Control Boards, which have the authority to regulate discharges to surface impoundments "by issuing waste discharge requirements, including discharge prohibitions, which implement water quality control plans" (Title 23, Chapter 3, Subchapter 15 of the California Administrative Code). But while minimum regulatory standards are established for various classes of impoundments under Subchapter 15, a specific exemption is provided for evaporation ponds and percolation ponds if "the applicable regional board has issued waste discharge requirements, reclamation requirements, or waived such issuance." To be eligible for the exemption, the discharge must also be nonhazardous and comply with the State Board's nondegradation policy and with "the water quality objectives set forth in the applicable water quality control plan...." For example, unlined sumps containing produced waters that could adversely affect freshwater aquifers would not be permitted in locations which could impact such aquifers.

Regional Water Quality Control Boards, while they must at least implement the requirements established by the State board, have the authority to establish requirements more stringent than those set by the State board. Thus, the regional boards may establish specific pit construction requirements (e.g., liners to prevent percolation from the sumps) in sensitive areas.

Any sump, other than an operations sump, containing a mixture of oil and water, must be covered with screening to restrain entry of wildlife. If the Department of Fish and Game deems the condition of a sump to be hazardous for wildlife, the Department notifies the Division of Oil and Gas, which requires the operator to abate the condition within 10 days (if an immediate or grave danger) or 30 days.

In addition to discharge to onsite saltwater sumps, substantial volumes of salt water are discharged to offsite sumps. These are discussed below.

Injection

Over half of the produced waters in California are reinjected, either for enhanced recovery or for disposal. The authority for management of Class II injection wells is delegated by EPA to the Division of Oil and Gas. The Regional Water Quality Control Boards, under a Memorandum of Understanding with the Division of Oil and Gas, may comment on Class II injection well permits on matters that could affect water quality, including degradation of ground water.

On Bureau of Land Management leases, operators of Class II wells must obtain permits from both the Division of Oil and Gas and BLM. Many of the injection wells are for enhanced recovery and therefore could significantly affect BLM's royalty earnings from its leases. As a result, BLM wants to maintain joint signatory authority on UIC permits. BLM and the Division of Oil and Gas are attempting to develop a Memorandum of Understanding on joint permitting.

Injection wells, other than those injecting steam, air, or pipeline quality gas, must be equipped with tubing and packer set immediately above the approved zone of injection. Exceptions may be granted where there is no evidence of freshwater-bearing strata, where more than one string of casing is cemented below the base of fresh water, or where the operator can demonstrate that freshwater and oil zones can be protected without tubing and packer. The pressure in the well must not be sufficient to fracture the zone of injection.

To obtain approval from the Division of Oil and Gas, operators must file plans, geologic analyses, evaluations of the impact of the planned well on other wells in the area, monitoring programs, the source and analysis of the water being injected, and analysis of water in the injection zone. A new chemical analysis of the water being injected must be filed whenever the source of the water is changed or as requested by the Division. Mechanical integrity tests (MITs) are carried out annually, except for thermal enhanced recovery wells and wells with special conditions. In these cases, MITs are performed on varying schedules--usually every 3 years.

Some disposal of salt water in California also takes place in combination with other oil field-related nonhazardous wastes in Class V wells; regulation of Class V wells has not been delegated to the State.

Any wells into which wastes defined as hazardous under California regulations are being injected, regardless of the Federal classification, would become subject to the requirements established in the Toxic Injection Well Control Act of 1985, which are generally more stringent than Federal requirements. These requirements are under the jurisdiction of the Department of Health Services.

Offsite Disposal

Central Sumps for Produced Waters

On the western side of the San Joaquin Valley, a series of large percolation/evaporation sumps receive produced water discharged to them through natural watercourse drainage. The Department of Energy has ordered the closure of two of these sumps, which are on the property of the Elk Hills Naval Petroleum Reserve; the two sumps no longer receive produced waters and are in the process of closure. The remaining sumps are still operating. Some of the wells discharging to the sumps, and some of the watercourses through which the discharges go, are on Federal lands managed by the Bureau of Land Management. Currently, most of the sumps either operate under requirements dating back two decades, or have no requirements at all.

While this disposal method currently is allowed, the Central Valley Regional Water Quality Control Board is considering whether these produced waters should be regulated under the requirements for California "designated" wastes (if they contain pollutants that exceed water quality objectives or could cause degradation of the waters of the State). There is also a question as to whether this method of disposal is in accordance with 435.32 of 40 CFR, since the discharge to the sumps is through natural watercourses, and the discharged waters generally do not meet the requirements for agriculture and wildlife use.

Waste Disposal Facilities for Drilling Wastes

Drilling wastes may be transported offsite for disposal. If hazardous by California's definition, the wastes must be disposed of (as required by Section 2521, Subchapter 15, Chapter 3, Title 23) in Class I waste management units (requiring double liners and no migration). If classified as "designated" wastes, they may be disposed of in Class II facilities (single liners, no migration, and design and construction "for the containment of the specific wastes which will be discharged") or Class I facilities. If nondesignated, alternative uses would be permissible.

Transport

An invoice for an undesignated waste is required for trucks hauling produced water. If being trucked to a central injection facility, the Division of Oil and Gas requires that the trucker carry a ticket designating the volume and source of the fluid. The operator of the central facility collects a copy of the ticket and files it.

Plugging/Abandonment

Under Section 3237 of the Public Resources Code, suspension of activity and removal of drilling activity is evidence of desertion of a well after 6 months. Removal of production equipment is evidence of desertion after 2 years. While the Supervisor of the Division of Oil and Gas may order the plugging of a well that has been deserted, the Division of Oil and Gas generally exercises its discretion for previously producing wells (particularly those that were permitted prior to the existence of a bonding requirement). Moreover, the Division actively communicates with operators about plugging wells that have been out of production for 5 years.

When a well is plugged, cement plugs generally should be placed across specified intervals to protect oil, gas, and usable water zones. Tne district deputy may allow cement to be mixed with or replaced by other substances with adequate physical properties. Intervals that are not plugged are to be filled with mud fluid of "sufficient weight and consistency" as to prevent movement of other fluids into the wellbore.

At the surface, the hole and all annuli must be plugged with at least a 25-foot cement plug. In an open hole, a cement plug must be placed from at least 100 feet below the bottom to at least 100 feet above the top of each oil or gas zone, and at least a 200-foot plug must be placed across all fresh-saltwater interfaces. Where the hole is open below the shoe, a cement plug is required from 50 feet below to 50 feet above the shoe.

In a cased hole, all perforations must be plugged with cement, and a plug must extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the oil or gas zone, whichever is highest. If cement is behind the casing across the fresh-saltwater interface, a 100-foot cement plug must be placed at the interface inside the casing. If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing is required through perforations to protect the fresh water, in addition to a 100-foot plug inside the casing.

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COLORADO

INTRODUCTION

Colorado has a long history of regulating oil and gas activities. As far back as 1889, Colorado passed a bill prohibiting the discharge of oil, petroleum, or other substances into any waters of the State. In 1927, a second bill was enacted that included provisions for well plugging. In 1951, the Oil and Gas Conservation Act was passed. The Solid Wastes Disposal Sites and Facilities Act was passed in 1973. The Solid Wastes Disposal Sites and Facilities Act (Title 30-20-Part 1, C.R.S. 1973, as amended) also has jurisdiction over oil and gas activities.

In 1985, Colorado produced 30,552,685 barrels of oil from 5,287 wells; 275,684 million cubic feet of gas were produced from 4,665 gas wells. Mud and air drilling are both encountered.

REGULATORY AGENCIES

The three agencies sharing regulatory authority for oil and gas wastes in Colorado are:

- Department of Natural Resources--Oil and Gas Conservation Commission;
- Department of Health; and
- U.S. Bureau of Land Management.

The Oil and Gas Conservation Commission has primary responsibility for the management of oil and gas exploration, development, and production activities in Colorado. The Commission is responsible for the conservation of oil and gas and the protection of the rights of all parties. It has general authority to protect the environment from pollution by oil and gas activities on the sites of drilling and production operations. The Commission is also responsible for the regulation and permitting of central disposal facilities operated by the producing companies.

The Colorado Department of Health, specifically the Water Quality Control Division/Commission and the Waste Management Division, has statutory and regulatory authority over solid waste disposal sites and facilities and NPDES permits, and is generally concerned with the endangerment of public health and the environment. Commercial disposal facilities for wastes from oil and gas production operations are subject to the Department's permitting and regulation. In addition, the Department is responsible for permitting of discharges for beneficial use for agriculture and wildlife.

Because the two agencies shared certain areas of responsibility under their statutes, they developed a Memorandum of Understanding in 1971 to specifically allocate responsibilities. Under this agreement, the Water Quality Control Commission of the Department of Health designated the Oil and Gas Conservation Commission as "its authorized representative to exercise authority for the administration of water pollution prevention, abatement and control required to protect the waters of the state from conditions and activities arising from the drilling, production and plugging of wells and all other operations for the production of oil and gas." This relationship has subsequently been clarified in the regulations of both agencies. The Department of Health regulations specify that the Department:

> "...will consider oil and gas liquid waste impoundments to be in compliance with these regulations if:

A. The disposal facilities are regulated by the Oil and Gas Conservation Commission,

B. There is no imminent or substantial endangerment to the public health or the environment from the disposal facilities, and

C. Compliance with the Certificate of Designation requirement is not required by the County within which the site is located (for central disposal facilities only)."

The U.S. Bureau of Land Management has jurisdiction over Federally-owned mineral rights. The U.S. Forest Service retains surface rights on Federally-owned forests and grasslands. EPA retains responsibility for approving underground injection wells on Indian land. The requirements of these agencies are discussed separately in the section on Federal agencies. (See Volume 1, Chapter VII.)

STATE RULES AND REGULATIONS

Drilling

Pit Requirements

Oil and Gas Conservation Commission rules require that "before commencing to drill, proper and adequate slush pits shall be constructed for the reception and confinement of mud and cuttings and to facilitate the drilling operation. Special precautions shall be taken to prevent contamination or pollution of state waters."

According to information provided by the Oil and Gas Conservation Commission, most wells are drilled using tanks rather than reserve pits; the reserve pits are used primarily when the mud is displaced during the running of pipe. While no rules prohibit the discharge of produced waters into a reserve pit, this is not commonly done. If the volume of produced water exceeded five barrels/day, this would make the reserve pits subject to the construction requirements and reviews in Rule 325. Otherwise, pits "for temporary storage and disposal of substances produced in the initial completion and testing or workover of wells drilled for oil and/or gas for a period of time not in excess of ninety (90) days" are excluded from application of many of the Rule's provisions.

Most drilling fluids and muds in Colorado are bentonite- and freshwater-based. Very few oil-based drilling fluids are used, and these are moved from operation to operation until disposed of into an approved landfill.

Pit Closure/Discharge

If the well is a dry hole and is abandoned, backfilling of pits and reclamation of the land must be completed within 6 months unless an extension is granted for unusual circumstances (Rule 319(a)(8)).

Generally, after the lighter fluids are decanted in the reserve pits, reserve pit sludges may be dried out and disposed of on the surface by tilling into the ground. The sludge may be removed to a different location before land disposal. The sludge may also be buried when the pit is backfilled. The Commission has permitted one facility for land discharge of wastes with limitations on total suspended solids, total dissolved solids, oil and grease, and chemical oxygen demand.

Produced Waters

Produced water is disposed of through reinjection (approximately 85 percent), placement in storage and disposal pits (approximately 15 percent), and discharge for beneficial use for agriculture and wildlife (<1 percent).

Disposal and Storage Pits

The Oil and Gas Conservation Commission regulates all produced-water storage or disposal pits except for the commercial disposal facilities regulated by the Department of Health. This includes both onsite and central pits. A central pit is a storage or disposal pit serving several leases or batteries in a field, and operated by one of more oil and gas operators under a field operator's agreement approved by the Commission.

Both central and onsite pits are subject to the requirements of Rule 325, which specifies informational, construction, and operating requirements. Minimally, such pits are required to have adequate storage capacity for the volume of produced water expected, and to be kept free of surface accumulations of oil or other hydrocarbons that could impede evaporation. Certain other requirements in the Rule do not apply where the volume of water to be disposed of does not exceed five barrels per day on a monthly basis.

Generally, applicants for permits to construct produced water disposal pits must provide substantial information on surface waters and ground waters, geology, and soil types in the area of the well. The application must also indicate the source and expected volume of water to be produced daily, and a chemical analysis of the water assessing all factors related to salinity. If a pit is located over permeable soil, and will receive, at full capacity, in excess of 100 barrels of fluid/day with a TDS content of 5,000 ppm or more, the operator must provide a plan for lining the pit and detecting leaks. Liners may be required where water placed in the pit has a higher TDS content than underlying aquifers hydrologically connected, regardless of the amount of water delivered to the pit.

The Commission makes a case-by-case determination on lining requirements for all produced-water storage and disposal pits on the basis of site-specific evaluations. According to information provided by the Commission, 90 percent of the pits for wells producing more than five barrels per day of water are required to be lined (approximately two-thirds with clay and one-third with synthetic liners). Of the remaining pits, either the received water is fresh and allowed to percolate, or the pits are over impervious shales and the water evaporates.

Injection

Produced water is reinjected into Class II wells both for enhanced recovery (667 wells) and disposal (134 wells). The UIC Class II injection program has been delegated to the Oil and Gas Conservation Commission.

Wells used for injection into oil or gas producing disposal zones must have "safe and adequate casing or tubing so as to prevent leakage, and shall be so set or cemented that damage will not be caused to oil, gas or fresh water resources." Detailed reports on fluids received and injected must be filed monthly.

Mechanical integrity tests must be performed on new injection wells before starting injection and every 5 years thereafter. The test pressure must be 300 psi or the minimum injection pressure, whichever is greater, and not more than the maximum injection pressure, with a pressure variance of no more than 10 percent. Monthly injection reports are submitted listing volumes injected and injection pressures. All injection facilities are inspected by the Commission staff on a routine basis.

Discharges for Wildlife and Agricultural Use

A few State facilities have permits from the Department of Health for effluent discharges under the BPT Wildlife and Agricultural Use Subcategory. The effluent limitations are:

pH	6.0 to 9.0
Total suspended solids	30 mg/L (30-day average) 45 mg/L (1-day maximum)
Oil and grease	10 mg/L
Total dissolved solids	5,000 mg/L (30-day average) 7,500 mg/L (1-day maximum).

Offsite Disposal

Commercial offsite produced water evaporation or evaporation/percolation pits are regulated by the Division of Waste Management of the Department of Health. According to information provided by the Department of Health, there are currently eight commercial disposal pits, half of which are lined. Lining requirements are determined by classifications of impoundments. Class I facilities (in a recharge area for a drinking water aquifer where seepage from impoundment would impair use of the ground water) require double liners with leak detection systems. Class II impoundments (where seepage would damage a freshwater aquifer if no liner were used) require single liners and monitoring systems. Class III impoundments (those located outside a recharge area, having competent bedrock between the surface and the aquifer, or where impairment would not result from unrestricted seepage) require no liners.

Truckers transporting produced waters to offsite impoundments or injection wells must file monthly reports on the source, volume, and recipient of the waters hauled. Similar records must be kept by the receiving facility. These records will be subject to computerized cross-tabulation.

Plugging/Abandonment

Wells that have ceased production or are incapable of production are to be abandoned within 6 months unless granted an extension by the Director of the Oil and Gas Conservation Commission (Rule 319(b)). In practice, if a well is shut down for economic reasons, the Commission will not require a formerly producing well to be plugged. If, however, the operator of the well has numerous wells that are closed down for economic reasons, and is operating all such wells under a single blanket bond, the Director may require the provision of individual bonds for each well. The operator must file a status report every 6 months indicating plans for future operations.

Wells must be plugged so as to confine oil, gas, or water to the original strata. The operator must obtain approval of the plugging method from the Commission prior to the plugging operation. Surface casing may not be removed from the well unless approved by the Director. Generally, requirements call for the placement of cement plugs 50 feet above and below each permeable zone, a 100-foot plug at the base of the surface casing, and a cement plug at the top of the surface casing. The operator may plug above perforated zones, or may squeeze with cement prior to abandoning the well or before recompleting into another formation.

References

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Personal Communication:

William R. Smith, Oil and Gas Conservation Commission (303) 866-3531.

FLORIDA

INTRODUCTION

Florida produced 14,090,000 barrels of oil and 15 x 10^9 cubic feet of gas in 1984. Production was from 165 oil wells; there are no producing gas wells. Virtually all drilling fluids as well as produced fluids are reinjected.

REGULATORY AGENCIES

The four agencies responsible for regulating the oil and gas industry in Florida are:

- Florida Department of Natural Resources, Division of Resource Management, Florida Geological Survey;
- Florida Department of Environmental Regulation;
- Florida Regional Water Management Districts; and
- U.S. Environmental Protection Agency, Region IV.

Primary regulatory responsibility rests with the Department of Natural Resources (DNR). DNR is the permitting agency for oil and gas wells, including approval to dispose of waste fluids by subsurface injection. The DNR regulates the exploration, drilling, and production of the oil and gas industry with respect to reporting, spacing, safety, and construction.

The Department of Environmental Regulation oversees the industry with regard to water quality standards and dredge and fill requirements (for pits) if oil and gas activities occur in wetlands of the State.

Florida's Regional Water Management Districts, which are separate regulatory groups on a local level, regulate oil and gas activities involving water use. Consumptive use permits are issued if applicable.

Other State agencies may be involved on a case-by-case basis. These agencies are most commonly the Florida Game and Freshwater Fish Commission, the Department of Community Affairs, and the Department of Transportation.

The State of Florida does not have primacy for Class II UIC program wells. The State operates a separate program for injection wells with a State permit and State inspections. A driller wishing to inject fluids underground must apply for a permit to do so from two separate governmental entities, the U.S. Environmental Protection Agency Region IV and the State, and undergo two sets of inspections.

STATE RULES AND REGULATIONS

Drilling fluids are put into pits during operation, but then are disposed of by reinjection. Pits are nearly dry when they are backfilled. They are lowered as fast as possible by pumping down the wellbore prior to plugging the well. All produced waters are reinjected.

The DNR is governed by Chapter 377, Florida Statutes, and its implementing rules, Chapters 16C-25 through 16C-30, Florida Administrative Code. One aspect of Chapter 377's specific purpose is to "require the drilling, casing, and plugging of wells to be done in such a manner as to prevent the pollution of fresh, salt, or brackish waters on the lands of the State." Section 377.371 further states that, "No person drilling for or producing oil, gas, or other petroleum products shall pollute land or water; damage aquatic or marine life, wildlife, birds, or public or private property."

UIC permits are issued pursuant to Chapter 403, Florida Statutes, and Chapter 17-28, Florida Administrative Code. If applicable, dredge and fill activities are regulated under Chapter 403, Florida Statutes, and Chapter 17-12, Florida Administrative Code. Water standards are issued under Chapters 17-3 and 17-4, Florida Administrative Code. Water management licenses (consumptive use) are issued under Chapter 373, Florida Statutes, by the regional Water Management Districts.

Plugging/Abandonment

Each request for temporary abandonment will be considered on a case-by-case basis; however, the requirements for temporary abandonment do not differ significantly from those for abandonment. Only the placement of a surface plug and the restoration of the surface area are not required.

When plugging an abandoned well, perforated intervals require cement retainers 100 feet above the interval, a 100-foot plug placed at the top of the retainer and cement squeezed into the interval, or a 200-foot plug extending 100 feet above and below the interval. With respect to the open hole below the casing string, a plug must be placed 100 feet above and below the casing shoe. A plug must be placed 100 feet above and below the casing stub if the casing is cut. Annular space must be plugged with a minimum 100-foot plug at the top of the casing. In uncased holes, 200-foot plugs must be placed opposite hydrocarbon formations and at contact points between saline and freshwater zones. Additional plugs must be placed in the casing of the smallest diameter (25-foot on dry land; 150-foot for wetlands).

References

Griffin, Lynn. Environmental Specialist. Department of Environmental Regulation. Letter to W.A. Telliard, EPA, March 22, 1985.

State of Florida regulatory and review procedures for land development. Chapter 14. November 1, 1984.

Wise, Lloyd. Region IV NPDES permit writer. 1985. Summary of EPA workshop presentation, Onshore Oil and Gas Workshop Meeting Report, July 1985.

Personal Communications:

David Curry, Florida Department of Natural Resources (904) 487-2219.

Lynn Griffin, Environmental Specialist, Department of Environmental Regulation, October 2, 1986 (904) 488-8615.

ILLINOIS

INTRODUCTION

Illinois produced 28,873,000 barrels of oil and 15 x 10^9 cubic feet of gas in 1984. Production is from 28,920 oil wells and 157 gas wells. Nineteen barrels of brine are produced for every barrel of oil. Seven thousand injection wells are operating in the State.

REGULATORY AGENCIES

Principally, one agency regulates the oil and gas industry in Illinois:

- Department of Mines and Minerals, Division of Oil and Gas.

The Department of Mines and Minerals operates under an Act in Relation to Oil, Gas, Coal and Other Surface and Underground Resources. Section 8A of the Act provides the Department with the power and authority to regulate the disposal of salt- or sulphur-bearing water and any oil field waste produced in the operation of any oil or gas well, and to adopt related rules and regulations. Section 8B provides that no person shall drill, convert, or deepen a well for the purpose of injecting gas, air, water, or other liquid into any underground formation or strata without first securing a permit. Section 8C(A) states that no person shall operate an oil field brine transportation system without an oil field brine transportation permit. Section 8G(3) specifies that the permittee shall not dispose of oil field brine onto or into the ground except at locations specifically approved and permitted by the Mining Board. No oil field brine shall be placed in a location where it could enter any public or private drain, pond, stream, or other body of surface or ground water.

The Division of Oil and Gas has UIC program primacy for Class II wells. While there are Federal lands in Illinois, there is no drilling or production on these lands at present. The Illinois Environmental Protection Agency has been delegated NPDES authority; however, no surface water discharges from the oil and gas industry are allowed.

STATE RULES AND REGULATIONS

Drilling

Before a new well is drilled, the operator must execute a bond of $2,500 unless the operator already has a blanket bond of $25,000. The bond is canceled only after the well has been plugged and all related restoration activities have been completed.

There are no State requirements that drilling pits be permitted or lined. Fluids from the pits may be disposed of in a dry drill hole. When the pit mud dries, the pit is backfilled and reclaimed. Pits must be reclaimed within 6 months after drilling ceases.

Production

Produced waters go into lined holding-evaporation ponds or are reinjected into certified injection wells. If pits are used, the lining must be an impermeable material that will prevent seepage. Most requests are for fiberglass- or concrete-lined pits. Earthen-lined pits have been substantially eliminated during the past 5 years. The Department of Mines and Minerals has been reducing the number of old pits by removing and injecting the produced waters, stabilizing the contents, applying topsoil, and vegetating the pit area.

Neither roadspreading nor landfarming is allowed.

Seven thousand injection wells for disposal or enhanced recovery are operating in Illinois, of which the majority are water flooding wells. Permits for injection wells must be obtained from the Division of Oil and Gas. The permit application must include the location and depth of any existing wells within one-half mile of the proposed new or converted injection well, as well as information to show that injection into the proposed zone will not initiate fractures through the overlying strata which would enable injection or formation fluids to enter freshwater strata. Injection must be through adequate tubing and packer.

A mechanical integrity pressure test must be carried out before injection is initiated. Thereafter, the well must be tested at least every 5 years (or, alternatively, monthly records of actual injection pressure in the casing-tubing annulus may be reported annually). Test pressures for new wells must be at 300 psi or the maximum authorized injection pressure, whichever is greater. The same range applies for newly converted wells or for retests, except that the ceiling is 1,000 psi.

Offsite Disposal

Offsite or commercial pits are not used in the State of Illinois. Brines may be transported offsite to injection wells. Transporters must have oil field brine hauling permits. Well operators must maintain detailed records of all brine removed from their leases and of the haulers contracted for the removal.

Plugging/Abandonment

A well must be plugged within 30 days of the cessation of drilling operations if no production casing has been run. Wells at which there have been no production operations for 6 months must be plugged unless the operator has been granted an extension. Requests for extensions will be granted by the Mining Board for good cause so long as all casing remains sound and in the well. The length of the extension is at the discretion of the Board. When an extension is granted, a bond is required from the operator if no bond covering the well is in effect. This bond remains in effect until the well is plugged. If, at expiration of the extension, the Mining Board denies a further extension, the well must be plugged and abandoned.

When plugging, cement plugs must be placed opposite any producing formation and extend 20 feet above the formation. Cement plugs must also be placed from 50 feet below to 100 feet above any coal seam thicker than 30 inches, from 20 feet below to 20 feet above the casing seat of the oil string, and from 10 feet below to 15 feet above the base of the surface casing. If the surface casing was not used, a 25-foot plug must be used below the surface with a 1-foot mushroom cap. Where a surface casing was used, the casing must be cut off 3 feet below the ground and a 1-foot cap should be added. Mud must fill the remainder of the well. There are no specific provisions for plugs over zones with potable water.

References

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USEPA. 1985. U.S. Environmental Protection Agency. Illinois Meeting Report. Proceedings of the Onshore Oil and Gas Workshop (March 26-27 in Atlanta, Ga.). Washington, D.C.: U.S. Environmental Protection Agency.

Personal Communication:

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INDIANA

INTRODUCTION

Indiana produced 4,758,609 barrels of oil and 367,084,000 cubic feet of gas in 1986. Production was from 7,600 oil wells and 806 gas wells.

REGULATORY AGENCIES

The two agencies that principally regulate oil and gas activity in Indiana are:

- Indiana Department of Natural Resources, Division of Oil and Gas; and
- U.S. Environmental Protection Agency, Region V.

The Indiana Division of Oil and Gas regulates the industry through Rule 310 IAC 7-1. No discharge to surface waters is allowed so that any involvement of the Indiana Department of Environmental Management would occur only as a result of the improper disposal of oil and gas wastes. Any concerns that owners of Federal lands may have regarding oil and gas surface treatment are satisfied through the conditions of the respective lease agreements.

The Oil and Gas Division does not have primacy for UIC program Class II wells; however, the State is in the process of attaining such status. Currently, anyone interested in underground injection must obtain two permits--one from the State and one from the U.S. Environmental Protection Agency.

STATE RULES AND REGULATIONS

Drilling

Adequate pits are required for muds or wastes associated with drilling operations. Drill pits must be reclaimed within 60 days after drilling has stopped. Fluids associated with such drill pits generally can be classified as fresh water and are mixed with bentonite clays. When a pit is closed, the practice is to pump the small amount of fluid in the pit to the surrounding land, bury the drill cuttings and other pit muds, and reclaim the land.

Production

Pits used for gathering production fluids and storing them until reinjection must be lined with impervious clay or an artificial liner. All production fluids must be reinjected underground. Evaporation pits were disallowed by the State 2 years ago.

Plugging/Abandonment

Any well that is not producing must be capped and sealed immediately. If not placed back in production within 2 years, the operator may be required to plug and abandon the well, to recase the well, or to demonstrate (through pressure testing or another approved method) that the well casing is in good condition and there is no commingling of fluids.

When the well is plugged, cement plugs are required from 50 feet below (or from the bottom of the well) to 100 feet above any stratum with oil, gas, or commercial deposits of coal. Where insufficient casing is set or surface casing was not cemented to the surface, production casing should be removed from 50 feet below the deepest aquifer containing potable water, and a cement plug should be placed from the remaining production string to 3 feet below the surface. In the case of a dry hole that has not encountered coal, a similar surface plug may be placed after filling the hole from the bottom with mud. The use of bridges is prohibited.

References

Interstate Oil and Gas Commission. 1986. Summary of State statutes and regulations for oil and gas production. June 1986.

Interstate Oil Compact Commission. 1985. The Oil and Gas Compact Bulletin, Vol. XLIV, No. 2, December 1985.

Personal Communication:

Mike Nickolaus, Indiana Division of Oil and Gas (317) 232-4055.

KANSAS

INTRODUCTION

Kansas produced 75,723,000 barrels of oil and 466.6 x 10^9 cubic feet of gas in 1984. Production is from 57,633 oil wells and 12,680 gas wells. Kansas ranks seventh in both U.S. oil production and U.S. gas production. There are 14,935 injection wells in the State.

Oil was found in Kansas in the 1860s, but it was not commercially developed until 1895. Oil and gas regulation began in 1935.

REGULATORY AGENCY

One agency regulates oil and gas activities in Kansas:

- Kansas Corporation Commission.

On July 1, 1986, by passage of House Bill 3078, the Kansas Legislature transferred the Department of Health and Environment's regulatory responsibilities for oil and gas activities to the Kansas Corporation Commission. Prior to that date, the Department of Health and Environment had responsibilities related to lease maintenance, emergency pits, drill pits, burn pits, storage ponds, and Class II oil field produced water and enhanced recovery injection wells. Under Kansas' Statutes (Chapter 55, Article 10, 55-1003) plans and specifications for the disposal of oil and gas produced waters and mineralized waters were to be submitted to and approved by both the State Corporation Commission and the Secretary of Health and Environment. Subsequent to the 1986 legislative action, the Secretary of Health and Environment no longer is a party to such action.

There are few Federal lands and little involvement of Indian tribes in the Kansas oil and gas industry. When an application for a permit to drill has been received, notice is published routinely in local news outlets. If requirements are specified by the Bureau of Land Management or Indian tribes, they are communicated directly to the driller through lease agreement conditions or by other legal means.

STATE RULES AND REGULATIONS

Drilling

The industry is regulated through the issuance of drilling and well operation permits. A compliance or surety bond is not required. With the recent departmental transfer of responsibilities, the Corporation Commission has revised and implemented regulations pertaining to those activities formerly administered by the Secretary of Health and Environment.

Pit Requirements

Until May 1987, drilling pits and burn pits were permitted and regulated under a general rule for a maximum period of 365 days unless the operator requested and received approval for an extension. A separate permit application was not required. Drilling pits may be used to temporarily confine "salt water, oil or refuse resulting from oil and gas activities during the drilling, completion or testing of any oil, gas, exploratory, wildcat, service or storage wells." Permits were required for emergency pits.

Liners are not required for drilling pits unless the Commission determines that a liner is necessary to protect soil or water resources in geologically or hydrologically sensitive areas. In such areas, liners or portable pits may be required. In areas with sandy soils, for example, drilling pits must be lined. In the heavy clay region of the north-central portion of the State, however, such pits most likely would not be lined.

Pit Closure

Onsite burial, after evaporation or mechanical dewatering, is the primary method of pit closure. After May 1, 1987, backfilling is required "as soon as practical or as required by the commission" after abandonment. Most lease agreements already contain such a requirement. Landfarming is prohibited. In geologically or hydrologically sensitive areas, in situ disposal of drilling pit contents can be prohibited.

Produced Waters

Injection

Ninety-nine percent of produced water is disposed of into injection wells for enhanced recovery (9,399 wells) or for saltwater disposal (5,536 wells). The Kansas Corporation Commission has primacy for the UIC Class II program. Operators may inject produced salt water into enhanced recovery or disposal wells after receiving approval of their applications from the Commission. Water injected into disposal wells may be returned to any mineralized water-bearing formation that is not oil or gas producing in the area of the proposed disposal, or to other subsurface water-bearing formations that contain or previously produced salt water or mineralized water exceeding 10,000 mg/L TDS. Enhanced recovery and waterflood injection wells must return water to an oil-producing zone, but not necessarily to the one from which it originated.

All injection and disposal wells requiring wellhead pressure to inject fluids must inject through tubing under a packer set immediately above the uppermost perforation or open-hole interval. The annulus between the tubing and the casing should be filled with a corrosion-inhibiting fluid or hydrocarbon liquid. Packerless or tubingless pressure completions may be authorized under special conditions. (For example, disposal through tubing without a packer must, among other requirements, have no surface wellhead pressure.) Wells must be cased and cemented in such a manner as to prevent damage to hydrocarbon sources or fresh and usable water sources.

Mechanical integrity tests must be conducted before injection begins and at least every 5 years thereafter. Packerless wells should be tested using a retrievable plug immediately above the uppermost perforation or open-hole zone. The test pressure must be 100 psi for old wells, 300 psi for new wells, or the authorized injection pressure, whichever is greater. The duration of the test is 30 minutes and the usual limit allowed for loss of pressure is 10 percent.

Other Storage/Disposal Practices

Spreading of salt water on roads under construction, as well as for maintenance, is allowed if approval is received from the Kansas Department of Health and Environment.

Requests for a surface pond permit are statutorily granted unless denied by the Commission within 10 days. According to proposed Rule 82-3-600, the Commission, in approving applications for surface pond permits, must consider the protection of soil and water resources from pollution. Each operator of a surface pond must install observation trenches, holes, or observation wells if required by the Commission, and seal the pond with artificial material if the Commission determines that an unsealed condition will present a pollution threat to soil or water resources. Surface drainage must be prevented from entering the pond. During the past 2 years, it has become a practice, on a case-by-case basis, to require monitoring wells in association with surface ponds and emergency pits in areas of shallow ground-water supply.

There are approximately 25 permanent pits, receiving a total of 30 barrels of produced water a day, mostly in the southeast corner of the State where there are no ground-water or seepage problems and where TDS concentrations of the produced waters are less than 10,000 ppm. Neither surface discharges of produced water nor pit disposal are allowed.

Upon the permanent cessation of the flow of fluids into any surface pond, all fluids resulting from oil and gas activities, plus rainwater (salt contaminated), must be removed to a disposal well approved by the Commission, or used for lease road maintenance or construction if approved by the Commission. Pond solids may be transported to a permitted solid waste landfill or to an approved offsite disposal area. Either action requires a permit from the Department of Health and Environment under the Kansas Solid Waste Statutes.

Offsite Disposal

Use is not made of offsite or commercial pits.

Plugging/Abandonment

Kansas Statute 55-156 states that prior to abandonment of any well that has been drilled, is being drilled, or may hereafter be drilled, the operator shall protect usable ground water or surface water from pollution, and from loss through downward drainage, by plugging the well in accordance with the rules and regulations adopted by the Commission. Failure to comply with these rules and regulations shall be a class E felony.

Within 90 days after operations cease on any well, the operator must plug the well or give notice of temporary abandonment. If no production has begun after a year, the operator must either reapply for temporary abandonment status or plug the well. Extensions are given for good cause, which means primarily for economic reasons. Temporary abandonment approvals are issued by the Commission only after a field inspection and fluid level measurement have been conducted to determine that there is no evidence of casing holes. A mechanical integrity test or remedial action on the well may be required if the water level measurement indicates problems.

Cement plugs of at least 50 feet in length must be placed above each present or past productive formation, and both above and below any freshwater horizons. Intervals between all plugs must be filled with approved heavy mud-laden fluid.

References

Interstate Oil and Gas Commission. 1986. Summary of State statutes and regulations for oil and gas production, June 1986.

Interstate Oil Compact Commission. 1985. The Oil and Gas Compact Bulletin, Vol. XLIV, No. 2, December 1985.

The State Corporation Commission of the State of Kansas. General rules and regulations, effective May 1, 1986.

USEPA. 1985. U.S. Environmental Protection Agency. Kansas Meeting Report. Proceedings of the Onshore Oil and Gas State/Federal Western Workshop (March 26-27 in Atlanta, Ga.). Washington, D.C.: U.S. Environmental Protection Agency.

Personal Communications:

Rick Hesterman, Kansas Corporation Commission (316) 263-3238.

Jim Schoff, Kansas Corporation Commission (316) 263-3238.

KENTUCKY

INTRODUCTION

Kentucky produced 7,788,000 barrels of oil and 61.5 x 10^9 cubic feet of gas from 8,798 gas wells, 19,334 oil wells, and 283 combination wells in 1984.

REGULATORY AGENCIES

The five agencies that regulate oil and gas activity in Kentucky are:

- Kentucky Division of Oil and Gas;
- Kentucky Department of Natural Resources and Environmental Protection;
- U.S. Bureau of Land Management;
- U.S. Army Corps of Engineers; and
- U.S. Environmental Protection Agency, Region IV.

The Kentucky Division of Oil and Gas, in the Department of Mines and Mining, issues drill permits and provides well casing and well plugging requirements. The State is seeking but does not yet have primacy for the UIC Class II well program.

The Kentucky Department of Natural Resources and Environmental Protection has NPDES-delegated authority. The Department issues permits for holding pits containing production fluids and instructions, pursuant to regulations, for pit construction.

The U.S. Army Corps of Engineers becomes involved in oil and gas activities on lands maintained for water management projects.

STATE RULES AND REGULATIONS

Drilling

Pursuant to Kentucky Regulation 401 KAR 5:090, there can be no discharge from a pit without an NPDES permit. Pits used to contain drilling muds or fluids associated with drilling activities have a permit by rule (under Title 401, Chapter 47 - Solid Waste Facilities) for construction and operation, provided that the pit life is no longer than 30 days after completion of exploration or drilling activities. Where the pit life is longer than 30 days beyond completion of exploration or drilling activities, the pit is defined as a holding pit and a facility-specific permit is required. When a pit is no longer in service, it must be backfilled and the land restored. There are no liner requirements for a drilling pit.

Production

A holding pit is a pit "designed to receive and store produced water at a facility." A holding pit must have a permit and must be lined with a synthetic material of 20 mil minimum thickness. The State may grant an exemption to the lining clause for pits that pre-existed the date of regulatory enactment. Construction requirements include at least 1 foot of freeboard and a 2-foot berm aboveground around the pit. Surface waters must be diverted from the pit.

No NPDES permits have been issued for discharges from holding pits. However, the Department of Natural Resources and Environmental Protection recently was sued and entered into a consent decree that specified a water quality criterion of 600 mg/L chloride as a 30-day average, with a maximum concentration not to exceed 1,200 mg/L at any time, as appropriate for receiving water quality. It is anticipated that there will be a number of requests for NPDES permits to discharge produced fluids.

Some holding pits are used as produced water storage pits until a contract hauler transports the fluids for well injection or other purposes. There is no manifest system per se, but the producer, the amount of fluid, and its destination following transportation must be reported. Most of the fluid goes into injection wells.

There is no roadspreading or landspreading of produced fluids in Kentucky. Some use currently is being made of mechanical evaporation.

Plugging/Abandonment

A well may be temporarily abandoned for cause for 2 years on a renewable basis. The well must be capped in such a way as to prevent the escape of oil, gas, or water from the well, or the entrance of foreign materials into the well.

When a well not drilled through a coal-bearing stratum is abandoned, it must be securely plugged "by placing above the oil-producing sand a plug of pine, poplar or some other material that will prevent the well from becoming flooded." After 7 feet of clay or sediment is placed above the plug, another plug of the same kind should be set. A similar combination of plugs and clay should be placed with the lower plug 10 feet below the casing [Sec.353.180]. Additional requirements are imposed for wells drilled through coal-bearing strata, including the use of cement plugs [Sec.353.120].

References

Interstate Oil and Gas Commission. 1986. Summary of State statutes and regulations for oil and gas production, June 1986.

Interstate Oil Compact Commission. 1985. The Oil and Gas Compact Bulletin, Vol. XLIV, No. 2. December 1985.

Personal Communications:

Brian C. Galpin, Kentucky Division of Oil and Gas (606) 257-3812.

Brad Lambert, Kentucky Department of Natural Resources and Environmental Protection (502) 264-3410.

LOUISIANA

INTRODUCTION

Louisiana produced 449,545,000 barrels of oil and 5,867 x 10^9 cubic feet of gas in 1984. Louisiana ranks third in U.S. oil production and second in U.S. gas production. Over half of Louisiana's 25,823 oil wells are strippers. More than two-thirds of the State's 14,436 gas wells are marginal (produce less than 60,000 cubic feet of gas per day). Eighty-five percent of all produced fluids is salt water.

State statutes have regulated drilling operations since 1940. On January 20, 1986, the Office of Conservation promulgated amended rules and regulations regarding "the storage, treatment, and disposal of non-hazardous oilfield waste."

REGULATORY AGENCIES

Four agencies regulate oil and gas activity in Louisiana. They are:

- Louisiana Department of Natural Resources, Office of Conservation;
- Louisiana Department of Environmental Quality;
- U.S. Bureau of Land Management; and
- U.S. Army Corps of Engineers.

The Louisiana Department of Natural Resources Office of Conservation regulates all subsurface and surface disposal of oil- and gas-associated wastes. These powers are delegated to the Office of Conservation under

Title 30 of the Louisiana Revised Statutes of 1950. The Office of Conservation has been granted primacy for all classes of UIC wells.

The Office of Conservation does not coordinate with EPA on NPDES permits, but does coordinate with the Louisiana Department of Environmental Quality, Office of Water Resources, on any problem discharges originating from oil and gas activities. The Office of Water Resources also permits discharges of produced waters and reserve pit fluids. The effluent standards incorporated in the permits represent DEQ-OWR policy; the proposed effluent regulations for oil and natural gas development have not yet been adopted. The regulatory basis for that policy is found in rather general rules (January 27, 1953) of the Stream Control Commission and a subsequent order (July 1, 1968) of the Commission.

The Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service. These rules, regulations, and orders are discussed in a separate section on Federal agencies. (See Volume 1, Chapter VII.) The Bureau of Indian Affairs has some jurisdiction in limited areas of Louisiana.

STATE RULES AND REGULATIONS

Drilling

Pit Construction/Management

Reserve pits used in the drilling of oil and gas wells do not have to be lined. However, Louisiana Statewide Order No. 29-B contains stringent operational requirements for reserve pits, including segregation of the drilling wastes in reserve pits from produced water or waste oil; protection from surface waters by levees, walls, and drainage ditches; and maintenance of 2-foot freeboard.

Pit Closure/Discharge

Reserve pits must be emptied of fluids and closed within 6 months of completion of drilling or workover operations. Prior to closure and for all closure and onsite and offsite disposal techniques except subsurface injection of reserve pit fluids, wastes must be analyzed for pH, oil, and grease, as well as a number of metal and salinity parameters. (An exemption to the testing requirement is granted for reserve pit fluids from wells drilled to less than 5,000 feet using freshwater "native" mud with limited amounts of bentonite, barite, or caustic soda.) Disposal of drilling and workover waste fluids at pit closure may be accomplished through annular injection, injection down another newly-drilled well that will be plugged, onsite land treatment, solidification and burial onsite, mixing waste with native soil and burial onsite, wastewater discharge, or offsite disposal at permitted commercial facilities.

The Water Pollution Control Division issues a standard permit to oilfield service companies to discharge wastewater from treated drilling site reserve pits and abandoned or inactive production pits in order to facilitate pit closure. This permit allows the discharge of fluids meeting the following maximum effluent limitations:

Oil and grease	15 mg/L
Total suspended solids	50 mg/L
Chemical oxygen demand	125 mg/L
Total chromium	0.5 mg/L
Zinc	5.0 mg/L
Chlorides	500 mg/L
pH	6.0 to 9.0.

There are provisions for dilution of the wastewater to meet the chloride limitation, provided all other parameters are met (i.e., predilution chloride concentrations must be less than 2,000 mg/L in freshwater areas and less than four times ambient chlorinity in brackish and saline areas).

Reserve pit fluids may be disposed of onsite if applicable technical criteria are met. For land treatment, burial, or trenching, waste/soil mixture must not exceed:

pH	6-9
Arsenic	10 ppm
Barium	2,000 ppm
Cadmium	10 ppm
Chromium	500 ppm
Lead	500 ppm
Mercury	10 ppm
Selenium	10 ppm
Silver	200 ppm
Zinc	500 ppm.

Onsite land treatment may be used to close pits containing only nonhazardous oil field wastes by mixing wastes with soil from pit walls or levees and adjacent areas, provided the resultant waste/soil mixture meets the above criteria, has an oil and grease content of no greater than 1 percent (dry weight), and meets additional parameters in freshwater wetlands not normally inundated and in uplands:

Electrical conductivity (EC)	< 8 mmhos/cm (wetlands) < 4 mmhos/cm (uplands)
Sodium absorption ratio (SAR)	<14 (wetlands) <12 (uplands)
Exchangeable sodium % (ESP)	<25% (wetlands) <15% (uplands).

Pits may be closed by mixing the waste with soil and burying the mixture onsite if it meets the above pH and metals limits, has a moisture content <50 percent by weight, EC 12 mmhos/cm, and an oil and grease content 3 percent by weight. The top of the burial site must be at least 5 feet below ground level and covered by native soil; the bottom should be at least 5 feet above the seasonal high water table.

Pits may be closed by solidification and onsite burial, using the same cover and depth requirements, if they have a pH of 6 to 12 and do not exceed the following limits in leachate tests:

Oil and grease	10.0 mg/L	Lead	0.5 mg/L
Arsenic	0.5 mg/L	Mercury	0.02 mg/L
Barium	10.0 mg/L	Selenium	0.1 mg/L
Cadmium	0.1 mg/L	Silver	0.5 mg/L
Chromium	0.5 mg/L	Zinc	5.0 mg/L.

The solidified material must also meet permeability, compressive strength, and wet/dry durability criteria.

Injection of drilling and workover waste fluids (including reserve pit fluids) may only be done at the well where used, and must not endanger underground sources of drinking water. Surface casing annular injection may be authorized if the surface casing is set and cemented at least 200 feet below the base of the lowest underground source of drinking water. Injection may be through perforations in the intermediate or production casing if that casing is set and cemented at a similar depth. Surface casing open-hole injection may be approved if, in addition to meeting the 200-foot requirement, there is a cement plug of at least 100 feet across the uppermost potential hydrocarbon zone.

Production

Pits

All production pits must be lined so that the hydraulic conductivity of the liner does not exceed 1×10^{-7} cm/sec. Liners may consist of clays, soils mixed with cement or clays, synthetics (at least 10 mil thickness), or any combination meeting the 1×10^{-7} cm/sec limitation. Production pits located within inland tidal waters, lakes bounded by the Gulf of Mexico, and saltwater marshes are exempted from the liner requirement provided they are part of an approved treatment train for removal of residual oil and grease. Natural gas processing pits and compressor station pits that collect and store process water and stormwater runoff are also exempted.

Surface Discharge

The current policy of the Office of Water Resources is that discharge of produced water is permitted into brackish and saline areas, with a discharge limit for oil and grease of 72 mg/L (monthly sample). A report is required on monthly volumes discharged and on oil and grease, and an annual report is required on chlorinity (though no limit is established). The discharge must be to an open-flowing water body of sufficient volume to prevent stratification and significant buildup of ambient salinity. The actual regulatory requirement states that "saltwater may be disposed of in normally saline waters, tidally affected waters, brackish waters or other waters unsuitable for human consumption or agricultural purposes."

Exceptions to the restriction against discharges in freshwater bodies are given for the Mississippi River and its tributaries below Venice and the Atchafalaya River below Morgan City.

New regulations, issued in November 1985, for the first time required that all of the above discharges be permitted. A mailing, sent out in 1986, required the filing of information and permit applications for current discharges. When these applications are received and evaluated, discharges actually occurring in freshwater areas not covered by the above exceptions would be required to end.

Injection

Over two-thirds of the produced water is reinjected for enhanced recovery or disposal, both onsite and commercial. Injection wells must be equipped with tubing set on a mechanical packer, no higher than 150 feet above the top of the disposal zone. Surface casing must be set through the deepest underground source of drinking water and cemented back to the surface. Long string casing must be cemented above the injection zone.

Mechanical integrity tests must be carried out at least every 5 years. Test pressures should be at the maximum permitted injection pressure, but within the interval of 300 to 1,000 psi. The test interval should be 30 minutes, with no greater than a 5 psi variance.

Offsite Disposal

Reserve pit contents can be transported offsite to permitted commercial land treatment or pit disposal facilities. Produced water can be transported to commercial underground injection wells.

Louisiana requires a substantial degree of financial commitment from commercial facility operators. Applicants for permits for commercial facilities must provide evidence of sufficient financial capability to ensure both adequate coverage of any liability incurred and a guarantee of funding for proper closure of the facility. A bond or irrevocable letter of credit must be provided for closing, based on closing costs estimated in the facility plan. Insurance against any liabilities that may be incurred must be provided through certificates of insurance, letters of credit, or other acceptable financial instruments. Required minimums are $1 million for commercial facilities operating open pits; $500,000 for commercial facilities that store, treat, or dispose of nonhazardous oil field solids; $250,000 for commercial saltwater underground injection/closed storage systems; and $100,000 for transfer stations operated in conjunction with permitted commercial facilities.

Commercial facilities may use lined pits for temporary storage, not permanent disposal, of nonhazardous oil field wastes. Such pits must be located on the site of the permitted treatment system, must not exceed 50,000 barrels capacity, and must have maximum hydraulic conductivity of 1×10^{-7} cm/sec.

Commercial land treatment facilities must be isolated from contact with water supplies, and are subject to extensive and continuous monitoring and sampling requirements. Limitations on concentrations and other parameters are established as maximums at any time in the treatment zone (a), at the time of closure in the treatment zone (b), and in surface runoff water from the facility (c):

	(a)	(b)	(c)
pH	6.5 - 9	6.5 9	6.5 - 9
Oil and grease	5%	3%	15 ppm
EC	10 mmhos/cm	10 mmhos/cm	0.75 mmhos/cm
SAR	12	12	10
ESP	15%	15%	

	(a)	(b)	(c)
TSS			60 ppm
COD			125 ppm
Chloride			500 ppm
Arsenic	40 ppm	10 ppm	0.2 ppm
Barium	3,000 ppm	3,000 ppm	undetermined
Cadmium	10 ppm	10 ppm	0.05 ppm
Chromium	1,000 ppm	1,000 ppm	0.15 ppm
Lead	1,000 ppm	1,000 ppm	0.1 ppm
Mercury	10 ppm	10 ppm	0.01 ppm
Selenium	10 ppm	10 ppm	0.05 ppm
Silver	200 ppm	200 ppm	
Zinc	500 ppm	500 ppm	1 ppm.

Commercial facilities may also receive permits to produce reusable materials from nonhazardous oil field waste. Such materials may be used as daily cover in sanitary landfills or as construction fill (subject to case-by-case review by the Commissioner). The oil and grease and metals leachate test limits are identical to those for leachate tests for solidification (above); the ESP, SAR, and pH limits are the same as those for treatment zones at commercial land treatment facilities; and EC is 8 mmhos/cm.

A complete manifest system to track the transportation and disposal of wastes taken to offsite commercial facilities is enforced.

Plugging/Abandonment

Wells must be plugged within 90 days of notice in the "Inactive Well Report" unless the operator submits a plan describing the well's future use; the well is then classified as having future utility.

When plugging, a cement plug of 100 feet must be placed above or across the uppermost perforated interval. Where production casing was not run or was removed, a cement plug must run from 50 feet below to 50 feet above the shoe of the surface casing. If freshwater strata are not protected by the casing, a cement plug must extend from 100 feet below to 150 feet above the deepest freshwater stratum, and a plug should be placed from 50 feet below to 50 feet above the shoe of the surface casing. A 30-foot plug must be placed at the top of the well. Additional plugs must be placed to contain high pressure oil, gas, or water sands. In wells completed with screen or perforated liners that cannot be practically removed, a 100-foot cement plug must be placed with its bottom as near as possible to the top of the liner or screen. Mud-laden fluids must fill those portions of the well not filled with cement.

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Lynn Wellman, Water Pollution Control Division, Office of Water Resources, Department of Environmental Quality (504) 342-6363.

MARYLAND

INTRODUCTION

In 1986 Maryland produced 20 million cubic feet of gas from six gas wells and no oil.

REGULATORY AGENCIES

The two agencies regulating oil and gas activities in Maryland are:

- Department of Natural Resources, Geological Survey; and
- Department of Health and Mental Hygiene, Office of Environmental Programs.

The Department of Natural Resources regulates oil handling, storage, and transportation. It issues drilling permits and regulates site erosion.

All wastewater regulation is managed by the Department of Health. Section 6-104 of the general public laws of Maryland provides that a person may not dispose of any product of a gas or oil well without a permit issued by the Department. The Department has both NPDES delegation and UIC program authority.

STATE RULES AND REGULATIONS

Drilling and Production

Drilling and production wastes are managed by the Department of Health, Office of Environmental Programs. There is no differentiation between pits that are associated with drilling or production activities.

A pit may be lined with an impervious material such as clay or a plastic to prevent ground-water pollution. Fluids introduced to lined pits generally are transported to a produced water disposal facility or to a sewage treatment plant, or they may be transported out of State for disposal purposes. There are no requirements on thickness or type of pit liners. There is no manifest system associated with transporting gas wastes unless such wastes are defined as hazardous.

Pits that are not lined must have a ground-water discharge permit issued under Code of Maryland regulations. The requirements associated with pit contents that would meet permit conditions for ground-water discharge are determined on a site-by-site basis. If there is surface discharge from a pit, an NPDES permit would be required.

Because of the absence of facilities, the State currently has issued neither an NPDES permit for surface discharges nor a UIC permit for underground injection. There is a ground-water discharge gas storage extraction facility in the western part of the State that is permitted to discharge about 1 million gallons per year. The permit requires that the first of a series of ten ponds be lined. There are periodic monitoring requirements for the ponds and a nearby stream, but there are no monitoring limits and no monitoring wells.

Offsite Disposal

The only offsite disposal pit used in the State is the one in western Maryland described above. Some transported production fluids are received by this facility.

Plugging/Abandonment

There are no specific requirements in the regulations relating to the time within which a well must be plugged.

When plugging, the well must be filled with mud, clay, or other nonporous material from the bottom (or from a bridge 30 feet below the lowest stratum) to 20 feet above the lowest oil, gas, or water-bearing stratum, at which point a cement plug should be placed. Similar filling and cementing steps should be taken for each oil, gas, or water stratum. A plug should be anchored about 10 feet below the bottom of the largest casing in the well, and the remainder of the well should be filled with nonporous material to within 2 feet of the surface.

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MICHIGAN

INTRODUCTION

Michigan produced 29,140,000 barrels of oil and 152,840 MMCF of gas in 1985 from 1,380 flowing wells and 4,480 pumping wells. In 1984, the State ranked 12th in U.S. oil production and 13th in U.S. gas production. Oil and gas production in Michigan peaked in 1980 and has been on a slight decline for the past 5 years.

The first successful Michigan oil well was drilled in 1886. The first oil and gas drilling permit was issued in 1927.

REGULATORY AGENCIES

The five agencies that regulate oil and gas activities in Michigan are:

- Michigan Department of Natural Resources;
- Michigan Department of Commerce, Public Service Commission;
- U.S. Forest Service;
- U.S. Bureau of Land Management; and
- U.S. Environmental Protection Agency.

The Michigan Oil and Gas Act of 1939 (PA 61) established the position of Supervisor of Wells and designated the Director of the Department of Natural Resources to that office. The Director, as authorized, appointed the Chief of the Geological Survey Division as the Assistant Supervisor of Wells to act on his behalf. The prime regulator of the oil and gas industry is the Assistant Supervisor of Wells and herein will be referred to as the Supervisor. The Supervisor has authority to subpoena, to establish well spacing requirements, to develop orders without legislative interference, and to control the disposal of solid and liquid wastes from drilling. The Oil and Gas Act provides the Supervisor with broad authority to regulate the industry from "cradle to grave"; it stresses "prevention of wastes" from exploration to well abandonment. The State requires a bond, an environmental assessment, and spacing minimums, and approves all well construction design.

The Water Resources Commission Act of 1929 (PA 245) regulates discharges to and the pollution of any waters of the State; NPDES permits are issued under Act 245. Michigan is an NPDES-delegated State, with such permits issued by the Surface Water Quality Division of the Bureau of Environmental Protection in the Department of Natural Resources. No NPDES permits are issued for oil and gas wastes.

The Solid Waste Management Act of 1978 (PA 641) provides for the licensing of solid waste disposal sites.

The State of Michigan does not require NPDES or landfill permits for disposal of liquid or solid oil field drilling wastes; these activities are regulated by the Supervisor of Wells. Law enforcement conservation officers of the Department of Natural Resources provide liaison with the Attorney General and the county prosecutors in dealing with local court actions. Where a ground-water problem has been identified through investigation and monitoring by the Geological Survey Division, and ground-water restoration is required, the Water Quality Division issues an NPDES permit for discharging the restored water.

The Air Quality Division of the Department of Natural Resources regulates gaseous emissions to the atmosphere, while the Michigan Public Service Commission regulates the production of gas from dry natural gas reservoirs and the safety of gas pipeline construction.

When drilling occurs on Federal lands, Federal review of the drilling applications depends on whether Federal ownership is restricted to surface rights or includes both surface and mineral rights. When only surface rights are owned by the Federal Government, a copy of the drilling application is sent to the Federal agency involved, generally the U.S. Forest Service. Two separate investigations follow: one by the Geological Survey and one by the U.S. Forest Service, which involves fish and wildlife, geological, and other Federal experts. A Federal surface use permit then is issued. The drilling application is not approved by the State until all reviews have been completed and pertinent comments have been made a part of permit conditions. When both surface and mineral rights are Federally owned, a copy of the drilling application is sent to both the U.S. Forest Service and the Bureau of Land Management.

The U.S. Environmental Protection Agency administers the UIC program for the State (40 CFR 147.1151).

STATE RULES AND REGULATIONS

Drilling

There are several pit construction/site management requirements. According to Instruction 1-84 (effective February 1, 1985) of the Supervisor of Wells, liners are required for mud pits when drilling with saltwater-based drilling fluids or when drilling through salt formations or brine-containing formations. While case-by-case exceptions to the requirement for lined drilling pits may, in principle, be approved when a well to be drilled will encounter only fresh water (as in the southern part of the peninsula), such an exception is rarely requested.

Liners for mud pits must be made of an impervious material that will meet or exceed the specifications for 20 mil virgin PVC. Liners of other than 20 mil virgin PVC must be approved by the Supervisor. Liners must be installed in a manner that would prevent vertical and lateral leakage, and must be either one piece or have factory-installed seams. Mud pits cannot be built where the ground-water table is observed at the depth of the proposed excavation. In such cases, steel tanks are used and the drilling muds are disposed of at an approved offsite location.

Instruction 1-84 restricts the use of mud pits to "drilling muds, drilling fluids, cuttings, native soils, cementing materials and/or approved pit stiffening materials." No salt cuttings from drilling may be released to the pit as solids; they must be screened out and dissolved before being released (via a closed system) to the pit.

Instruction 1-84 also requires that cellars be sealed and rat and mouse holes be equipped with a closed-end steel liner or otherwise sealed or cased so that all fluids entering the cellar, rat hole, and/or mouse hole would not be released to the ground, but would instead be discharged to steel tanks, the lined reserve pit, or the mud circulation system. Aprons of 20 mil virgin PVC or other equivalent material should be installed under steel mud tanks and overlapping the mud pit apron, and in ditches or under pipes used for produced water conveyance from cellars to pits or to steel mud tanks.

Pit Closure

At closure, all free liquids above the solids in the mud pits must be removed to the maximum extent possible and either reused or disposed of. The remaining mud pit solids may be required to be stiffened (mixed with earthen materials). In any event, the residue is encapsulated and buried onsite or removed to an approved waste disposal site. For onsite disposal, the edges of the pit liner must be folded over the pit, and a separate piece of 10 mil virgin PVC should be used to entirely encapsulate the pit. The top of the cover must be buried at least 4 feet below grade. The Supervisor may require additional measures under special circumstances.

For abandoned pits, or pits used prior to Special Order 1-81 issued in 1981 and not meeting its specifications, no action is taken unless a contamination problem has been detected. When a potential contamination problem exists, the site is investigated by the Survey's ground-water unit. If it can be shown that an identifiable entity is responsible, damages may be sought administratively or through the courts.

Disposal

Free liquids from the mud pits must be pumped off prior to encapsulation, either for disposal or for use in the drilling of additional wells. Fluids may be disposed of in Class II injection wells.

Two additional options are specified in Special Order 1-85. The Supervisor may authorize the disposal of fluids onsite to dry holes as part of plugging operations. Under rare conditions, where production casing is run, fluids generated during drilling of the well may be injected in the annular space. In both cases, drilling fluids must be injected in permeable formations isolated below freshwater horizons.

Prior to Special Order 1-85, pit fluids were allowed to be spread on roads for dust and ice control. A 1983 estimate showed that 22 million of the 28 million gallons of pit fluids generated during the year were spread on roads. Special Order 1-85 prohibited the use of pit brines for ice control on March 29, 1985, and prohibited their use for dust control as of September 1, 1985.

Offsite disposal in approved lined landfills with leachate collection systems is also permitted.

Produced Fluids

Injection

Over 90 percent of Michigan's produced waters are now disposed of by injection into Class II wells. Such wells must have a surface string of casing that is cemented and completely isolates the freshwater aquifers from the downhole disposal zone.

The wells must be "cased and sealed to prevent the loss or injection of brine into any unapproved formation." Wells must be equipped with tubing and packer. Since Michigan does not have delegated UIC authority, EPA's Region V directly implements the mechanical integrity test program. Wells are required to meet a standard pressure test of 300 psi for 30 minutes, with 3 percent allowable bleed-off.

Annular disposal of produced waters is prohibited. Although exceptions are technically allowed under the regulations, none have ever been requested.

Surface Disposal

Produced waters were formerly used for both ice and dust control in Michigan. Special Order 1-85, issued on March 29, 1985, immediately banned the use of produced water for ice control. The use of produced waters for dust control may continue through September 12, 1987 (provided the produced waters meet specifications for benzene, toluene, and xylene content). Annual 1-year extensions may be granted allowing continued use of brine for dust control. Such 1-year extensions may continue until a 3-year DNR environmental impact study has been completed. The decision as to whether to allow continued road application of produced waters will be based on the results of this study.

Offsite Disposal

Solid drilling wastes may be disposed of in an approved, licensed solid waste landfill, with the agreement of the landfill operator, where the landfill is lined and has a leachate collection system, a ground-water monitoring system, and a treatment process prior to the discharge of waste leachate.

Road disposal of produced waters remains temporarily available for dust control; producers may provide produced waters to a hauler if the hauler can verify in writing the authorization to receive produced waters on behalf of a governmental unit.

Plugging/Abandonment

Plugging operations must begin within 60 days after completion as a dry hole or within a year after cessation of production. Extensions may be granted by the Supervisor if there are sufficient reasons for retaining the well.

Oil, gas, produced water, and fresh water should be confined to the strata in which they occur by use of muds, cement, or other suitable materials; both the materials and methods of placement must be specified and approved by the Supervisor. The surface pipe is abandoned with the hole and must be cut off below plow depth and sealed with a cement plug or other approved material.

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Bill Shaw, DNR Office of Water Quality (517) 373-8088.

Rex Tefertiller, Permits, Geological Survey Division (517) 334-6974.

MISSISSIPPI

INTRODUCTION

Mississippi produced 31,879,000 barrels of oil in 1984 from 3,569 oil wells; 210 x 10^9 cubic feet of gas were produced from 715 gas wells.

REGULATORY AGENCIES

Four agencies regulate the oil and gas activity in Mississippi:

- State Oil and Gas Board;
- Mississippi Department of Natural Resources, Bureau of Pollution Control;
- Department of Wildlife Conservation; and
- U.S. Environmental Protection Agency, Region IV.

The State Oil and Gas Board regulates the oil and gas industry "to prevent the pollution of freshwater supplies by oil, gas, or saltwater" and to promote, encourage, and foster the oil and gas industry (Section 53-1-17, State Statutes). The Oil and Gas Board does not have UIC program authority.

The Department of Natural Resources, Bureau of Pollution Control, is responsible for the investigation of water pollution and for the issuance of NPDES permits. No NPDES permits are issued for drilling fluids, completion fluids, workover fluids, or produced waters generated by the onshore oil and gas industry.

The Department of Wildlife Conservation is responsible for the maintenance of fish and wildlife within the State.

The U.S. Environmental Protection Agency, Region IV, issues UIC program Class II injection well permits for Mississippi. In this activity area, the State Oil and Gas Board maintains a separate well injection permitting program; a well operator must obtain an injection permit from both the Federal and State governments.

A 1982 Memorandum of Agreement among the Department of Natural Resources, Department of Wildlife Conservation, and the State Oil and Gas Board coordinates the activities of the three State agencies related to the oil and gas industry. The Agreement ensures that the Mississippi Commission on Wildlife Conservation has an opportunity to review the drill plan, as drilling may impact the sensitive environmental nature of the State's wetland resources. The Agreement further allows for suspension of a lessee's operations by the Oil and Gas Board where any signatory agency determines such operations to be in violation of applicable laws or regulations.

STATE RULES AND REGULATIONS

Drilling

The use of drilling reserve pits or mud pits does not require a special permit; the permit to drill constitutes the permit for the drilling reserve pit. Reserve pits must be constructed to prevent pollution of surface or subsurface fresh waters. The only specific construction requirements in the regulations are that the pit must be protected from surface waters by dikes and drainage ditches, and that no siphons or openings may be placed in the walls or dikes that would permit the contents of the pit to escape.

The reserve pit must be emptied of fluids, backfilled, and compacted within 3 months of the completion of drilling operations. Exceptions may be granted if warranted, and the reserve pits may be used as test pits, with the agreement of the Board's field representative, if they meet the conditions for well test pits.

When closing the reserve pit, there are several options for disposing of the drilling muds. Where the well is a dry hole, the muds may be pumped back into the hole before plugging and abandonment, provided the surface casing has been set to a point below the base of the USDW. They may be landfarmed if they will "not . . . cause contamination of soils." The muds may be hauled to a commercial disposal facility designed to handle drilling muds. The muds may also be treated in the pit with flocculants to aid in precipitation, coagulation, and sedimentation. The supernatant water is then sampled in place to determine that it does not exceed the following limits established by the Department of Natural Resources in its "Reserve Pit Discharge Policy":

Chlorides	500 mg/L
pH	6 - 9
Suspended solids	100 mg/L
Specific conductance	1,000 mmhos/cm
COD	250 mg/L
Zinc	5 mg/L
Chromium	0.5 mg/L
Phenol	0.1 mg/L.

If the fluids meet this limit, they can be discharged. These discharges are considered to be part of the policy covered by the drilling permit and do not require a separate discharge permit. The Oil and Gas Board is in the process of incorporating these limits formally into their pit regulations (in Rule 63, Section III.E.9). After the discharge, the dewatered muds are covered in place and the pit is closed as noted above.

Production

Pits

The regulations of the State Oil and Gas Board contain a provision, now a decade old, requiring that earthen pits "be phased out and discontinued, except as hereinafter provided." The regulations further specify limited conditions under which specific types of pits may be used, and the requirements that must be met in their construction and management. When permits are issued for pits (other than reserve pits), the longest permit period is 2 years. In addition to reserve pits, permits are issued for four types of pits:

(1) Temporary saltwater storage pits: The Board's regulations stipulate that this type of pit will be "permitted only if no other means of storing or disposing of salt water is available" (e.g., in remote areas). When permitted, these pits must be lined with an impervious material, must have no siphons or openings in the walls or dikes and must be protected from surface waters by dikes and drainage ditches. Only produced waters should be placed in the pit (after separation), and fluid levels should never rise to within 1 foot of the top.

(2) Emergency pits: Produced water should never intentionally be placed in such pits, but only in the event of an emergency such as a saltwater disposal or water injection system failure. A field representative of the Board must be notified within 72 hours. Within 2 weeks after the emergency period, the pit must be emptied so as to contain no more than 2 feet of water. The fluid level must never rise to within 1 foot of the top of the pit; there must be no siphons or openings in the walls of the pit; and dikes and drainage ditches should be used to protect the pit from surface water.

(3) Burn pits: These pits may be used to burn tank bottoms and other refuse products. The burn pit must be placed at least 100 feet away from the facilities for storing and/or treating the oil or gas, must be constructed to prevent the escape of contents or ingress of surface water, must never have fluid levels closer than 2 feet to the top of the pit walls, and must not be used for noncombustible fluids (except as these are naturally associated with the combustible wastes).

(4) Well test pits: These are small pits used in testing producing wells for short periods of time. Well test pits must be placed at least 100 feet away from the facilities for storing and/or treating the oil or gas, must be constructed to prevent escape of contents or ingress of surface water, and must maintain a 2-foot freeboard.

When any of these pits is abandoned, it must be emptied of fluids, backfilled, leveled, and compacted.

There are areas where even this use of pits is prohibited. In areas where public water supplies or recreational, wildlife, or fishery resources would be adversely affected (e.g., coastal wetlands), "impervious containers shall be used . . . [and] the contents removed and properly disposed of within ninety days following usage."

Injection

Annular disposal of produced salt water is permitted. The Board's policy is that disposal in the annulus is allowed only where the operator can absolutely show that there is no endangerment to the environment or fresh ground water, and can demonstrate that there is no economic alternative. The applicant must provide the Board with an economic study of the well and of the economics of alternative methods of disposal. Generally, such an economic demonstration could only occur in a setting in which there was no well that could be converted to an injection well; this would likely be in remote, small fields. The applicant would be required to provide the Board with a radioactive tracer survey to prove that the injected fluid was not leaking through the casing and was entering the correct zone.

As noted above, Mississippi does not have the delegated authority for the regulation of Class II wells. The State does, however, issue permits for all injection wells, and operators must obtain permits from both EPA and the State Oil and Gas Board. The State regulations require information on wells within one-fourth mile of the proposed injection well, injection pressure limited to 75 percent of estimated fracture pressure of the target formation, injection through tubing and packer set no more than 150 feet above the injection zone, and mechanical integrity tests before initial injection and every 5 years thereafter. Test pressures are required to be at the maximum authorized injection pressure or 300 psi (for a new well), whichever is greater, with a ceiling of 500 psi (for a converted well).

Offsite Disposal

Except for two commercial pits in southern Mississippi, both of which are phasing down, use is not made of offsite and commercial pits within the State.

Plugging/Abandonment

All wells that are drilled and found dry must be plugged within 120 days, unless an extension is granted by the Supervisor. A production or service well that ceases to operate must be listed on the Inactive Well Status Report after 6 months. The operator must classify the well as having future utility or having no future utility. If the "future utility" designation is accepted, no further action is necessary. If the latter designation is assigned, the well must be plugged within 120 days.

When plugging a well in which the production casing has been set, if the production casing is not to be pulled, a cement or bridging plug must be placed near the bottom of the casing string to protect any producible pool. If the production casing is to be pulled, the following placements should be made: a cement or bridge plug at the bottom of the production string; a 100-foot cement plug about 50 feet below all freshwater-bearing strata; additional plugs to protect freshwater sands; a 100-foot plug at the bottom of the surface pipe; and a plug at the surface. The remainder of the hole must be filled with mud.

When plugging an uncased hole, 100-foot plugs must be placed to protect each producible pool. Additionally, 100-foot plugs must be placed approximately 50 feet below all freshwater-bearing strata and at the bottom of the surface pipe. A plug must be placed at the surface of the ground so as not to interfere with soil cultivation.

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MISSOURI

INTRODUCTION

Missouri produced 131,000 barrels of oil from 557 oil wells in 1984. There is no commercial gas production. The State has 9 evaporation pits and 229 injection wells. In 1984, Missouri had a total of 2.6 million barrels of produced waters, most of which were injected. The reason for injection exceeding production is that two major steam operations import fresh water to steam out the oil, which results in an increased quantity of injectable fluids. Missouri has had no commercial gas production since 1977.

REGULATORY AGENCIES

Two agencies regulate oil and gas activities in Missouri. They are:

- Department of Natural Resources, Division of Geology and Land Survey; and
- U.S. Bureau of Land Management.

The State Oil and Gas Council was formed by Rule 10 CSR 50-1.010 and is composed of the executive heads of the Division of Geology and Land Survey, Division of Commerce and Industrial Development, Missouri Public Service Commission, the Clean Water Commission, the University of Missouri, and two persons with knowledge of the oil and gas industry, appointed by the Governor with the advice and consent of the Senate. The State Geologist, who serves as Director of the Division of Geology and Land Survey, is charged with the duty of enforcing the rules, regulations, and orders of the Council. The State has primacy for UIC program Class II wells.

Federal lands in Missouri are confined to U.S. Air Force bases, but there is drilling on these lands. When a request for a permit to drill is received, the Bureau of Land Management prepares the draft permit, which is issued by the State Oil and Gas Council.

The Department of Natural Resources, Division of Environmental Quality, becomes involved only when there is a breach of a pit dike and a spill of fluids occurs. Appropriate action is then taken under the Division of Environmental Quality regulations.

STATE RULES AND REGULATIONS

Drilling

Rule 10 CSR 50-2.040 provides requirements during the drilling of wells to prevent contamination of either surface or underground freshwater resources. Bonding is required before oil or gas drilling operations are initiated and all wells must be plugged when abandoned.

There are no regulations related to drill pits. Drill pits are not lined. When pit muds dry, the muds are buried onsite.

Produced Waters

There are no regulations related to construction of evaporation/percolation pits for produced waters. About 32,370 barrels of produced waters were put in such pits in 1984.

Remaining produced waters are injected into Class II wells for disposal or enhanced recovery. Injection wells must be completed with strings of casing properly cemented at sufficient depths to protect any freshwater strata. The specific casing and cementing requirements will be based on the depth to the base of the lowest underground drinking water source, the nature of the fluids being injected, and the hydraulic relationship between the injection zone and the base of the underground source of drinking water. Maximum injection pressure must be established by the State Geologist to avoid fracturing the confining zone.

All injection wells must be tested for mechanical integrity before initiating injection and at least every 5 years thereafter. Procedures may include a pressure test, monitoring of annulus pressure after an initial pressure test, or other methods deemed effective by the State Geologist.

Offsite Disposal

Some of the produced fluid is trucked to other injection sites. No manifest is required for the transportation of produced water.

Plugging/Abandonment

Notification is required within 90 days after operations cease, and the Council may specify temporary plugging to prevent pollution of freshwater strata. After 6 months, the operator must plug and abandon the well unless granted an additional 6-month extension for good cause. Further 6-month extensions may be granted, up to a limit of 2 years.

Plugging must assure that all fluids remain in their original strata. Cement plugs must be placed from the bottom of any oil or gas stratum to at least 25 feet above the top of that stratum. Appropriate means must be taken to prevent migration of surface water into a plugged well. Casing must be cut off below plow depth.

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Personal Communication:

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MONTANA

INTRODUCTION

Montana produced 20,079,819 barrels of oil and 52,981,382 billion cubic feet of gas in 1984. Production is from 4,665 oil wells and 2,152 gas wells. A total of 622 wells were drilled for oil and gas in 1985. About 320,000 barrels of produced water per day are produced from the approximately 1,600 full-producing oil wells. The remaining stripper wells each produce about 40 barrels of produced water per day.

REGULATORY AGENCIES

The four agencies that regulate oil and gas activities in Montana are:

- Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division;
- Montana Department of Health and Environmental Sciences, Water Quality Bureau;
- U.S. Environmental Protection Agency, Region VIII; and
- U.S. Bureau of Land Management.

The Oil and Gas Conservation Division issues drilling permits and regulates the oil and gas industry in Montana. There is a compliance bond. Montana does not have primacy for the UIC program, but the Board of Oil and Gas Conservation is planning to negotiate with EPA on assumption of privacy.

The Montana Department of Health and Environmental Sciences, Water Quality Bureau, controls water quality issues. The Bureau has primacy for the issuance of NPDES permits.

Region VIII of the Environmental Protection Agency issues UIC permits for the injection of produced water in Montana.

The Bureau of Land Management uses its own form for drilling permits; thus, a driller must obtain a State as well as a Federal permit to drill for oil or gas on Federal lands. The Board of Oil and Gas Conservation has a cooperative agreement with the Bureau of Land Management concerning spacing of wells and field rules on Federal lands. BLM issued the permits to drill on Indian lands. The Board has no jurisdiction over Indian lands, but does maintain files on those wells if the operation chooses to file the permit requests and reports that would be required on other wells.

STATE RULES AND REGULATIONS

Drilling

Permits are not required for drilling pits. The regulations of the Oil and Gas Conservation Division (36.22.1005) require the operator to "contain and dispose" of drilling operation wastes either by removal from the site or burial at least 3 feet below the surface of the land. Further, the operator is required to "construct his reserve pit in a manner adequate to prevent undue harm to the soil or natural water in the area. When a salt base mud system is used as the drilling medium, the reserve pit shall be sealed when necessary to prevent seepage."

The lining requirement for reserve pits is decided case by case, based upon soil composition, slope, drilling, fluids, and proximity to water sources. Fluids may be removed from reserve pits by several methods. One method is to remove fluids by truck and haul them to another drill site or disposal facility. No manifest is required for transporting fluids. Another method is to allow fluids, other than oil, to remain in a reserve pit for up to a year for evaporation. Alternatively, the fluids may be treated chemically so that they can be used for beneficial purposes. After the fluids have been removed, the remaining solids are left to dry before backfilling. If a plastic liner has been used, it is folded into and buried in the reserve pit.

Produced Waters

Full-producing wells in Montana produce approximately 200 barrels per day of produced water; strippers yield about 40 barrels per day. Most produced water is reinjected, but some is disposed of by evaporation. A small amount is disposed of by discharge for beneficial use.

Rule 36.22.1227 of the Board of Oil and Gas Conservation states that salt or brackish water may be disposed of by evaporation when impounded in excavated earthen pits, which can only be used for such purpose when the pit is underlaid by tight soil such as heavy clay or hardpan. At no time should salt or brackish water impounded in earthen pits be allowed to escape over adjacent lands or into streams.

Rule 36.22.1228 allows salt water to be injected into the stratum from which it is produced or into other proven saltwater-bearing strata. Injection is also permitted to producing formations to enhance production of oil and gas. The UIC program, however, is administered by EPA Region VIII.

NPDES discharge permits are issued by the Water Quality Bureau of the Montana Department of Health and Environmental Sciences for 18 facilities under the beneficial use provision of the wildlife and agricultural use subcategory with a total permitted discharge of 0.6 million gallons per day. Of those issued, only about two of the permitted facilities discharge. Discharges are made to a closed basin in the northern part of the

State. Discharge limits include total dissolved solids of less than 1,000 mg/L and an oil and grease limit of 15 mg/L absolute with an average of 10 mg/L. Other discharge limits including phenols and metals are imposed.

Plugging/Abandonment

Once a well is no longer being used for the purpose for which it was drilled, it should be plugged. Nevertheless, a well can remain idle on a field with other producing wells while being held for possible future use (unless causing damage to oil, gas, or freshwater strata). At the point that other wells in that field cease to produce because of depletion of the reservoirs, however, the operator must commence drilling and abandonment operations within 90 days. Before plugging work begins, the operator must submit forms laying out the specific plans for plugging. After approval by the Petroleum Engineer, plugging may proceed.

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Personal Communications:

Abe Horpestad, Water Quality Bureau (406) 444-2459.

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NEBRASKA

INTRODUCTION

Nebraska produces 6,470,000 barrels of oil and 2,347 MM cubic feet of gas each year. Production is from 2.072 oil wells and 18 gas wells. Most of the State production is in two areas: the five-county area in the Denver basin and Red Willow and Hitchcock Counties. Strippers account for about 85 percent of the State production.

REGULATORY AGENCIES

The three agencies that regulate oil and gas activity in Nebraska are:

- Nebraska Oil and Gas Conservation Commission;
- Nebraska Department of Environmental Control; and
- U.S. Bureau of Land Management.

The Nebraska Oil and Gas Conservation Commission regulates industry practices and procedures with regard to construction, location, and operation of onsite drilling. The Commission issues permits for oil and gas drilling and UIC Class II wells. The Commission has three members who are appointed by the Governor. At least one member must have experience in oil or gas production.

Nebraska is an NPDES-delegated State. The Nebraska Department of Environmental Control issues all NPDES permits and regulates all other classes of UIC wells.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. The Bureau is addressed in a separate section.

STATE RULES AND REGULATIONS

Drilling

When drilling is complete, the supernatant in mud pits is allowed to evaporate. The muds in use are generally freshwater gels. After the mud pit has dried, the residues are landspread and the pit is backfilled.

Production

Under Rule 3.002, "No salt water, brackish water, or other water unfit for domestic, livestock, irrigation, or general use shall be allowed to flow over the surface or into any stream or underground fresh water zone." Produced water may be disposed of by evaporation pits, road spraying, or injection.

Pits

Generally, evaporation pits are used in the panhandle where net evaporation is as high as 60 inches annually. Under Commission Rule 3.022, retaining pits must be permitted. The Commission approves or disapproves the pit upon receipt of the application. The pits are required to be lined or constructed with impermeable material when the underlying soil conditions would permit seepage to reach subsurface freshwater zones. They must have the capacity for at least three times the average daily fluid influx into the facility.

This rule does not apply to burn pits or emergency pits. Burn pits are required to be a safe distance from any other structure, and must be constructed to prevent any materials from escaping from the pit or surface water from entering the pit. Open pit storage of oil is only allowed during an emergency or by special permission from the Director of the Commission.

Road Spraying

Road spraying of produced water is considered on a case-by-case basis. When allowed, spraying must be done with a spreader bar and in such a way as to prevent runoff.

Injection

In southwest Nebraska, most produced waters are reinjected, either into disposal or enhanced recovery wells. There are about 500 Class II wells in Nebraska and most are used for enhanced recovery. Injection wells must be completed, maintained, and operated to confine injected fluids to approved formations, and to prevent pollution to fresh water or damage to sources of oil or gas. Along with injection well applications, information must be submitted on other wells within one-half mile of the proposed injection well, as well as a demonstration that injection will not lead to vertical fractures allowing injection or formation fluids to enter freshwater strata. Injection must be through adequate casing or casing and tubing. Mechanical integrity tests must be at 125 percent of the maximum authorized injection pressure or 300 psi, whichever is greater. (Alternatively, for wells without tubing and packer, the operator should record the actual injection pressure weekly and report it monthly.)

Plugging/Abandonment

There are no specific time requirements related to plugging of a well. It is State policy to encourage operators not to permanently plug wells that have any further potential for secondary recovery operations. Before plugging, the operator must notify the Director of the plans for plugging, but the regulations make no mention of specific requirements for positive approval or for having witnesses to the plugging.

The well must be plugged with "mud-laden fluid, cement, mechanical plug or some other suitable material" in order to prevent migration of oil, gas, or water from the strata of origin.

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NEVADA

INTRODUCTION

During 1984, Nevada produced 1,953,000 barrels of oil from a total of 34 oil wells. There are no producing gas wells in this State. All of these wells are on Federal land and most use reserve pits to evaporate drilling fluids. Reinjection is applied to produced waters. Between 200,000 and 500,000 barrels per year of waters are produced in Nevada's major production area (the Carbonate Belt). Reinjection of these waters is accomplished collectively into some five to nine injection wells. No produced waters are discharged under the beneficial use subcategory. Nevada has NPDES primacy, but is currently negotiating for UIC primacy.

REGULATORY AGENCIES

- The four agencies that regulate the oil activity in Nevada are:

  - Nevada Department of Minerals;
  - Nevada Department of Conservation and Natural Resources, Division of Environmental Protection;
  - Bureau of Land Management (BLM); and
  - EPA, Region IX, Underground Injection Section.

The Nevada Department of Minerals, created as a single State department by the State legislature in 1983, regulates the industry on the State level with respect to construction, location, and operation of onsite drilling and production, and issues all operation permits. Operators must obtain permits from both the Department and BLM.

The Division of Environmental Protection in the Department of Conservation and Natural Resources has adopted Underground Injection

Control Regulations governing the use of all types of injection wells. As of April 1987, the U.S. Environmental Protection Agency had not yet granted delegation of the program to the State; however, it is expected that by October 1987, the State will be administering the program.

The Division also regulates the disposal of solid waste and supervises the cleanup of any major spills of pollutants. The discharge of any produced waters during the exploration and testing phase is also regulated. Depending on the quality of the discharge waters and the nearby surface and ground waters, discharge to the surface may or may not be allowed.

The Division has jurisdiction over all waters of the State, both surface and ground waters, and regulates activities on State and Federal lands.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. For such drilling, the Bureau of Land Management handles all Applications to Drill. The Bureau requires extensive environmental documentation, including environmental assessments, and develops environmental impact statements for drilling on Federal land.

U.S. EPA Region IX regulates the underground injection of wastes from oil wells under the UIC program. The applicable regulations are found in 40 CFR 144 and 146. Operators must obtain permits from both the U.S. EPA and the Division of Environmental Protection. Upon delegation of the UIC program to the State, EPA will no longer issue permits.

Further discussion of BLM and U.S. EPA UIC regulations can be found in the section on Federal regulations. (See Volume 1, Chapter VII.)

STATE RULES AND REGULATIONS

The Regulations and Rules of Practice and Procedures under Chapter 522 of the Nevada Revised Statutes of the Oil and Gas Conservation Law were adopted by the Department of Minerals on December 20, 1979. Section 200.1 of these rules states that, "Fresh water must be protected from pollution whether in drilling, plugging or producing oil or gas or in disposing of salt water already produced." The regulations govern the "drilling, safety, casing, production, abandoning and plugging of wells." The regulations do not include a provision for allowing or disallowing discharges nor is there mention of a discharge allowance. Section 308, however, states that all excavations must be drained and filled and the surface leveled so as to leave the site as near to the condition encountered when operations were commenced as practicable. Section 407 declares that "Oil or oil field wastes may not be stored or retained in unlined pits in the ground or open receptacles except with the approval of the Division." Finally, Section 600.1 states, "The underground disposal of salt water, brackish water, or other unfit for domestic, livestock, irrigation or other use, is permitted only upon approval of the Administrator."

Plugging is required for wells with production casing that have not been operated for a year, and for wells without production casing in which drilling operations have ceased for 30 days. Six-month extensions may be granted for good cause. Plugging should be done with cement and heavy mud in order to seal hydrocarbon or water formations.

References

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Personal Communications:

Dan Gross, Division of Environmental Protection, Department of Conservation and Natural Resources, September 26, 1986 (702) 885-4670.

Ellis Hammett, Permit Processor, Nevada Bureau of Land Management, September 26, 1986 (702) 784-5123.

Nate Lau, Director, UIC Division, EPA Region IX, September 26, 1986 (415) 974-0893.

Cathy Loomis, Engineering Technician, Nevada Department of Minerals, September 26, 1986 (702) 885-5050.

NEW MEXICO

INTRODUCTION

New Mexico produced 78,500,000 barrels of oil and 893.3×10^9 cubic feet of gas in 1985, ranking fourth in U.S. gas production and eighth in U.S. oil production. Production is from 21,986 oil wells and 18,308 gas wells. Twenty percent of oil production is from the stripper well category.

REGULATORY AGENCIES

The following agencies have responsibilities for regulating oil and gas activities in New Mexico:

- New Mexico Energy and Minerals Department, Oil Conservation Division;
- New Mexico Oil Conservation Commission;
- New Mexico Water Quality Control Commission; and
- U.S. Bureau of Land Management.

The Oil Conservation Division of the Energy and Minerals Department is responsible for regulating the oil and gas industry. It protects water quality by regulating exploration and drilling, production, and refining.

The Oil Conservation Commission has "concurrent jurisdiction and authority with the division to the extent necessary for the Commission to perform its duties as required by law." The three members of the Commission are the Commissioner of Public Lands, the Director of the Oil Conservation Division, and the State Geologist. The Commission serves as an appeals body for permit applicants who object to decisions of the Division; the applicant must seek review from the Commission before going to court. The Commission may also initiate rules and orders to be administered by the Division, as in the case of Orders R-3221 and R-7940, which restrict surface discharges of produced water in areas of the State with vulnerable aquifers (see below).

New Mexico has relatively few specific statewide regulations relating to freshwater protection from oil and gas discharges because of the diversity of the climate, geology, and quantity and type of waste that is produced. Statewide rules require that all fresh surface and ground waters be protected from contamination. Statewide UIC rules have been adopted, and there is a plugging bond requirement that endures until well abandonment has been approved by the Division.

The Oil and Gas Act also allows for the adoption of special rules or orders tailored to the particular characteristics of a production area. As a result, rules have been adopted controlling specific disposal practices in various geographic areas of the State.

The U.S. EPA has the responsibility for NPDES permitting in New Mexico; however, the Environmental Improvement Division of the New Mexico Health and Environment Department certifies those permits. No NPDES permits have been issued for the New Mexico oil and gas industry drilling and production facilities.

The Water Quality Control Commission (WQCC) is an interagency commission with members from several State government agencies, including the Environmental Improvement Division and the Oil Conservation Commission. The WQCC is responsible for the development of water quality control standards and water pollution regulations. It delegates the administration of the regulations it develops to constituent agencies. WQCC is prohibited from taking any action that would interfere with the exclusive authority of the Oil Conservation Commission over all persons and things necessary to prevent water pollution resulting from oil or gas operations.

The Oil Conservation Division administers WQCC regulations at oil refineries and natural gas processing facilities. The Environmental Improvement Division administers and enforces WQCC regulations at brine manufacturing operations, including all brine production wells, holding ponds, and tanks. The Oil Conservation Division regulates brine injection through its Class II UIC program if the brine is used in the drilling for or in the production of oil and gas.

The U.S. Bureau of Land Management (BLM) takes the lead in oil and gas drilling activities on Federal and Indian lands. When drilling on Federal land occurs, the BLM issues a drilling permit, but concurrence by the State is required. The State maintains primacy in waste disposal activities associated with any drilling or production activities.

Issues involved when drilling on Indian lands currently remain unresolved. Some tribes have issued regulations concerning oil and gas drilling and production activities. Other tribes have applied for UIC program delegation. The State has not waived jurisdiction over the regulation of the oil and gas industry on Indian lands, however. Nevertheless, in instances where tribal regulations go beyond those of the State, the tribal regulations prevail.

STATE RULES AND REGULATIONS

New Mexico has developed many of its rules in response to problems identified or anticipated in particular production areas in the State.

In the southeast, contamination is only now being detected that resulted from oil and gas activities which occurred three or four decades ago. These cases may be related to improper casing, pit construction, improper plugging, or any number of practices. Contamination includes increases in chlorides and total dissolved solids, dissolved aromatic and phenolic hydrocarbons, and natural gas.

In northwest New Mexico, contamination has mainly involved the seepage of natural gas into water wells. An active plugging program for old abandoned wells is in effect. Since little ground-water monitoring has been performed in northwest New Mexico, the extent of contamination from casing leaks or unlined pits is unknown. In many areas, contamination is unlikely because of deep ground water; thick, low permeability vadose zones; and small volume discharges. Additional investigations are being carried out by the Division in shallow ground-water areas.

Drilling

There is a general regulatory requirement that the operator must provide a drilling pit sufficient for the accumulation of drill cuttings, and that drilling fluids and drill cuttings must be disposed of at the well site in a manner that will prevent contamination of surface or subsurface waters. There are, however, no specific rules on construction of such pits. The District Supervisor would be responsible for determining if a potential problem exists in vulnerable areas.

No drilling fluids are authorized to be discharged to surface waters. Land application is generally not done, although there are no specific statewide rules on landfarming. The reserve pits are usually dried out through evaporation and the dried muds are buried in the pits. The areas of New Mexico in which oil and gas drilling occurs have significant net evaporation. In the southeast, annual rainfall averages 14 to 17 inches, with 80 inches of evaporation. In the northwest, rainfall averages 7 to 12 inches annually and evaporation is 40 to 50 inches.

Removal of drilling fluids or drill cuttings for offsite disposal must be approved by the appropriate District Supervisor.

Produced Waters

Storage/Disposal Pits

Regional Orders determine the requirements for saltwater storage or disposal pits in the areas of the State where oil and gas production predominates. In 1967, Order No.R-3221 prohibited most surface disposal of produced waters in a four-county area in southeastern New Mexico. In 1985, another set of regional regulations (Order No.R-7940) was established, effective January 1, 1987, for areas in the northwestern part of the State with potentially vulnerable aquifers.

In the southeast, Order R-3221 prohibits the disposal of produced water onto the ground or into unlined pits because of the presence of shallow ground water, which could be adversely affected by the produced water. An exemption is made for pits receiving no more than 1 barrel/day per 40-acre tract, with a maximum of 16 barrels/day for any pit. An amendment to the Order (R-3221-B) excepted areas in the four counties where the only water present was already highly saline.

In the northwest, Order R-7940 defines areas where aquifers are vulnerable to the effects of produced water and prohibits unlined pits in such areas. Exemptions are made (as long as ground-water depth is at least 10 feet) if a pit receives no more than five barrels per day of produced water and the water is less than 10,000 mg/L TDS, or if the pit receives no more than one-half barrel per day.

Lined pits may be permitted in areas where unlined pits have been prohibited. Order R-3221-C states that "the utilization of lined evaporation pits is feasible and in the interest of good conservation practices, provided they are properly designed, constructed and maintained." Order R-7940 authorizes administrative approval of lined pits or below grade tanks within the Vulnerable Area "upon a proper showing that the tank or lined pit will be constructed and operated in such a manner as to safely contain the fluids to be placed therein and to detect leakage therefrom."

Operators must obtain approval from the Division for lined pits, and appropriate requirements for pit construction are found both in R-3221-C and in "Guidelines for the Design and Construction of Lined Evaporation Pits." R-3221-C requires that the pit provide at least 600 square feet of evaporative surface for each barrel deposited in the pit on a daily average basis throughout the year, and that the lease or leases served by the pit should have an even or decreasing rate of water production. Header pits must be provided to prevent oil from reaching the evaporation pits. Pits must be lined with an impervious material at least 30 mil in thickness and have leak detection capability.

Other Surface Discharge

No NPDES permits are issued for discharges of produced waters, and no discharges to surface waters are allowed. However, individual farmers may contract to use produced water as drinking water for cattle (although not for irrigation). Agreement must be obtained from the District Supervisor. No specific limits are placed on produced water used for this purpose, nor does the approval of the District Supervisor constitute certification that the quality of the produced water is satisfactory for such a purpose.

Injection

Over 90 percent of the produced water is reinjected into wells for enhanced recovery (3,508) or saltwater disposal wells (363). The Oil Conservation Division has responsibility for the Class II UIC injection permitting program.

Generally, disposal of produced waters into zones containing waters of 10,000 mg/L or less TDS will not be permitted except after notice and hearing, unless the water being injected is of higher quality than the native water in the zone. The Division may establish exempted aquifers for such zones, however, where such injections may be approved administratively.

Regulations impose the general requirement that injection wells must be cased with safe and adequate casing or tubing to prevent leakage, and the casing or tubing must be set and cemented to prevent the movement of formation or injected fluid from the injection zone into any other zone or to the surface around the outside of any casing string.

Failure of any injection well must be reported immediately. Where injected fluids have not been confined to the authorized zone or zones, the wells may be restricted as to volume or pressure of injection, or shut in until the failure is identified and corrected.

Before injection, wells must be tested to assure the "initial integrity of the casing and the tubing and packer, if used, including pressure testing of the casing-tubing annulus." Tests should last for 15 minutes at pressures in the range of 250 to 300 psi, with a maximum variance of 10 percent. Additional tests are required at least every 5 years.

Offsite Disposal

Production and drilling wastes are sometimes sent to commercial or centralized surface disposal or collection facilities. Commercial facilities are those receiving compensation. Centralized facilities are noncommercial facilities "receiving produced water, drilling fluids, drill cuttings from any off-well-site location for collection, disposal, evaporation, or storage in surface pits, ponds, or below grade tanks." The Commission issued Order No. R-7940-A in 1986 to regulate such offsite facilities in the northwest. For commercial pits, the Division may approve use of either lined or unlined pits, so long as they are constructed adequately to protect fresh water. For proposed centralized pits, applications must be filed with the Division, unless the facility will never receive more than 16 barrels/day in a 24-hour period and is at least 10 feet above ground water, or serves emergency purposes during drilling for periods not exceeding 10 days. Applications are required in all instances where the pits receive drilling or completion wastes.

Where lining is required, pits must be lined according to the provisions of the "Guidelines" for lined evaporation pits. The "Guidelines" require that the pit must provide the minimum evaporative surface necessary for the maximum yearly volume of water to be discharged to the pit. It should have adequate freeboard to protect against wave action, and levees at least 18 inches above the ground. It must have a double liner system, with a leak detection system between the top and bottom liners. Synthetic liners must be at least 30 mil thick. Skimmer ponds or tanks must be used to separate any oil from the water prior to its discharge to the evaporation pit.

Transporters of oil field wastes must register, but need keep no records of source, destination, and volumes of the specific wastes hauled.

Plugging/Abandonment

Wells cannot be temporarily abandoned for more than 6 months unless a permit for temporary abandonment has been approved by the Division. The maximum period of the permit is 1 year, with an additional 1-year extension possible. The Division may waive this limitation and grant further extensions in the case of a remote or unconnected gas well, a presently noncommercial gas well that could become commercial in the foreseeable future, or a currently nonproducing well with commercial potential in a field where secondary recovery has been demonstrated to be commercially feasible. Such further extensions are limited to 2 years but are renewable.

Before a permit for temporary abandonment can be granted, evidence must be furnished that the condition of the well is satisfactory and will not allow damage to producing zones or contamination of fresh water. A one-well plugging bond may be required for any well granted an extension for temporary abandonment.

Specific well-plugging plans must be approved by the Division. The general regulatory requirement is that plugging must "confine all oil, gas, and water in the separate strata originally containing them. This operation shall be accomplished by the use of mud-laden fluid, cement and plugs, used singly or in combination as may be approved by the Division."

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Personal Communication:

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NEW YORK

INTRODUCTION

New York is one of the pioneer States for oil and gas production and use. Proven oil reserves were documented in 1627 and drilling began in the late 1800s. Since then it is estimated that 30,000 to 50,000 wells have been drilled in New York.

New York produced 1,071,000 barrels of oil from 4,621 wells in 1985. Thirty-five billion cubic feet of natural gas were produced from 4,818 gas wells in 1985.

REGULATORY AGENCIES

Background

In 1963 the New York legislature passed laws regarding oil and gas operations. A working permitting system was instituted in 1966 under the purview of the Department of Environmental Conservation. The regulations have been revised frequently over the last 20 years. In fact, further revisions are expected in the next few years as a result of a Generic Environmental Impact Statement scheduled for completion in late 1987.

Agencies

Oil and gas activities in New York are regulated by:

- New York Department of Environmental Conservation;
- Bureau of Land Management (Federally-held mineral rights only); and
- U.S. Forest Service (surface activities in U.S. forests).

Most oil and gas activities in New York are regulated by the Department of Environmental Conservation (DEC). The Department is authorized to regulate the "development, production, and utilization of natural resources of oil and gas . . . in such a manner that a greater ultimate recovery of oil and gas may be had." DEC also has authority for "prevention of pollution and migration." New York is NPDES-delegated, with the Department of Environmental Conservation responsible for the program. New York does not have UIC primacy.

An Oil, Gas, and Solution Mining Advisory Board (with 11 members, a majority of whom are industry representatives) meets a minimum of twice a year, and is charged with providing DEC with its recommendations on developing rules and regulations that could impact the oil and gas industry.

The U.S. Bureau of Land Management has regulatory authority for oil and gas activities when mineral rights are Federally held. The Bureau's regulations are discussed in a separate section, Federal Agencies. (See Volume 1, Chapter VII.)

The U.S. Forest Service has jurisdiction over surface activities on Federal forest lands even when mineral rights are held privately.

The Water Quality Division, Fish and Wildlife Division, and the Regulatory Affairs, Law Enforcement, and Lands and Forests Divisions, provide instrumental manpower and enforcement actions, when applicable.

STATE RULES AND REGULATIONS

Drilling

The Division of Mineral Resources in the Department of Environmental Conservation issues all oil and gas drilling permits. The Mineral

Resources Regulations establish a general objective that must be incorporated in all permits: "Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited." Each permit requires that the fluids generated by drilling be "hauled away and properly disposed of." The regulations do not provide specific guidance regarding what practices constitute proper disposal. Rather, the operator must submit and receive approval of a plan for the "environmentally safe and proper ultimate disposal of such fluids."

If drilling muds are freshwater natural clay-based muds, they are considered nonpolluting and are specifically excluded from this requirement. Muds contaminated with oil or other pollutants must be disposed of in a certified landfill. Drilling pits are dewatered and the fluids are disposed of properly prior to reclamation. During reclamation, pit liners are shredded or removed and the rock cuttings are disposed of in situ. After drying, the cuttings are buried.

Other drilling wastes must be disposed of or discharged in a manner acceptable to the Department considering the environmental sensitivity and geology of the area. Historical experience with drilling operations in the same area may also be used in considering an application. In addition to the drilling permit, permits may be required for disposal or discharge of drilling wastes (excluding drilling muds).

Since 1982 DEC has required that all drilling pits be properly constructed, sized, and lined. It is a permit condition on all wells. The only exception has been the closely observed, pitless drilling experiments associated with some air-drilled wells.

DEC has noted that most of the wells in New York are drilled with air, and there is very little fluid associated with the drill cuttings in the drill pit. As a result, there has been some experimentation with pitless drilling, which DEC reports "creates a temporary dust problem and some vegetation is killed by the associated brine, but less than would be killed by clearing the land for a drilling pit."

Produced waters generated during drilling are considered "polluting fluids" in the Mineral Resources Regulations. These and other polluting fluids may be stored in watertight tanks or lined pits for up to 45 days after drilling ends prior to disposal. An extension may be granted if the operator plans to use the fluids for later activities. The disposal alternatives for produced waters generated during drilling would generally be the same as those for waters generated during production.

The Department is also responsible for well construction and spacing requirements.

Produced Water

Part 556 of the Mineral Resources Regulations addresses operating practices applicable to oil and gas wells. Section 556.5 prohibits pollution of the land and/or surface or ground fresh water resulting from producing, refining, transportation, or processing of oil, gas, and products. Brine (i.e., produced water) may be stored in watertight tanks or in lined pits prior to disposition. Although specific construction requirements are not described in the regulation, pits must be constructed and lined to prevent percolation into the soil, or over or into adjacent lands, streams, or bodies of water.

The only disposal alternative described in the regulation is injection. The Department of Environmental Conservation has procedures for application and approval of permits to inject produced waters; since

New York does not have primacy for the UIC program, an operator would have to obtain a permit from EPA Region II as well.

According to DEC, the predominant method of disposing of the dilute produced waters associated with oil production in the old waterflooded fields of New York is under NPDES permits. Roadspreading is the principal produced water disposal method for the concentrated brines associated with the State's gas wells. Roadspreading is conducted on a manifest system under a separate permit. Criteria for roadspreading are established on a case-by-case basis and include such requirements as time of day, use of spreading bar, prohibition on spreading during rainstorms, and concentration limits.

The Department of Environmental Conservation allows "processing [of brines] at sewage disposal plants, permitted onsite discharges, and hauling to other States with approved disposal facilities." DEC allows produced water discharges from stripper wells under permits with the following limitations:

Oil and grease	15 mg/L
pH	6 to 9
Benzene	10 micrograms/L
Toluene	10 micrograms/L
Xylene	10 micrograms/L.

Sampling is done infrequently on any given well. Annular disposal is not allowed.

Offsite Disposal

New York regulations do not address the use of offsite pits for long-term storage or disposal.

Plugging/Abandonment

Wells that are commercially producible may be shut in for 1 year, and may be granted additional 1-year extensions (renewable) for good cause. Wells may be temporarily abandoned for only 90 days without specific permission, but extensions for a "reasonable time period" will be granted and renewed for good cause.

The wellbore must be filled with cement from the bottom of the well to 15 feet above the shallowest formation from which production was ever obtained in the vicinity. Alternatively, a bridge topped with 15 feet of cement may be placed above each formation from which production was ever obtained. If the casing is left in the well, 15-foot plugs must be placed at the top and bottom. If the casing extending below the deepest potable water is not to remain, a 15-foot plug must be placed 50 feet below that water level. If the surface casing is withdrawn, a 15-foot plug should be placed immediately below where the lower end of the casing rested, and the well should be filled with cement from that point to the top. Intervals between plugs must be filled with heavy, mud-laden fluid. If the casing left in the hole was never cemented, it must be perforated and cement-squeezed into the annular space. Additional requirements to ensure proper abandonment are added by permit condition.

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NORTH DAKOTA

INTRODUCTION

North Dakota produced 45,624,000 barrels of oil and 62 x 10^9 cubic feet of gas in 1986. Production was from 3,595 oil wells and 103 gas wells.

REGULATORY AGENCIES

The following three agencies regulate oil and gas activity in North Dakota:

- North Dakota Industrial Commission, Oil and Gas Division;
- U.S. Department of Agriculture, Forest Service; and
- U.S. Bureau of Land Management.

The North Dakota Industrial Commission, Oil and Gas Division, has the regulatory responsibility to oversee the drilling and production of oil, protect the correlative rights of the mineral owners, prevent waste, and protect all sources of drinking water. Other responsibilities of the Division are to collect monthly reports on oil, gas, and water; oversee proper disposal of produced water; and issue drilling permits. The Division also has primacy for UIC Class II wells and issues such permits.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands, but the operator must obtain a permit from the Oil and Gas Division. When drilling is to occur on U.S. forestland, the operator must obtain a State permit and meet additional stipulations required by the U.S. Forest Service.

STATE RULES AND REGULATIONS

Drilling

Before a drilling permit is issued by the Commission, the operator of the well must be bonded. Single well bonds are $15,000, a 10-well bond is $50,000, and a blanket bond is $100,000. The Commission will release the bond after site restoration is approved. Before drilling activities get underway, Commission inspectors will survey the site for pit location. The inspectors also decide whether or not to require a pit liner at the site.

Under Commission Rule 43-02-03-19, "Pits shall not be located in or hazardously near, stream courses, nor shall they block natural drainages. Pits shall be constructed in such a manner as to prevent contamination of surface or subsurface waters by seepage or flowage therefrom. Under no circumstances shall pits be used for disposal, dumping or storage of fluids, wastes and other debris not used in drilling operation." Within 1 year after the completion of a well, the pit site must be restored. Pit restoration does require approval from the Commission. Reclamation includes removing the fluid from the pit and redistributing the topsoil that was removed from the site at the start of drilling activities.

When drilling is on U.S. forest lands, the U.S. Forest Service has stipulations in addition to those of the Commission. The Forest Service requires a complete survey and design of the drilling site. This survey must be approved before drilling. All reserve pits must be lined with a material that meets the minimum requirements set by the Forest Service. The reclamation plan must also be approved by the Forest Service before implementation.

Production

Under Commission Rule 43-02-03-53, "All saltwater liquids or brines produced with oil and natural gas shall be disposed of without pollution of freshwater supplies. At no time shall saltwater liquids or brines be allowed to flow over the surface of the land or into streams." Surface pits are not allowed for produced water storage. Surface tanks are allowed provided they are diked and leak-proof.

Produced water may be disposed of by use of injection wells for either enhanced recovery or disposal. When use of a central tank battery or central production facility is planned, approval must be received from the Commission or from the Forest Service if on U.S. forest lands. Both methods require permits issued by the Commission. All injection wells must be cased and cemented to prevent the movement of fluids into or between the underground sources of drinking water. Plans for drilling a well must include an analysis of all other pits within the applicable area of review, the initiation of corrective action, if needed, on other wells penetrating the injection zone, and the evaluation of appropriate pressure to avoid generating or spreading fractures in the confining zone. Mechanical integrity tests must be carried out before injection is initiated and at least every 5 years thereafter (although regular monitoring of the annulus pressure or records showing a consistent relationship between injection pressure and flow rate may be used in lieu of later pressure tests). Wells must be pressure tested for at least 15 minutes. Test pressure is dependent upon maximum injection pressure. Allowed pressure variance depends upon the stabilized test pressure and maximum injection pressure.

Offsite Disposal

The State has several commercial produced water disposal wells but no pits. The produced waters hauled onto commercial facilities are stored in tanks.

Plugging/Abandonment

A well may be temporarily abandoned (generally for economic reasons) and no casing can be pulled without the approval of the enforcement officer. A plug must be placed at the top of the casing. Wells that have been shut in for long periods will be reviewed on a case-by-case basis, including tests of casing integrity. A well in which drilling operations have been suspended for 6 months must be plugged and abandoned unless a permit for temporary abandonment has been obtained.

When wells are plugged, perforations must be squeezed or a cast iron bridge plug must be set above the perforations and capped with five sacks of cement. Cement plugs are set 50 feet in and 50 feet over the top of each productive zone; a 100-foot plug is set half in and half over the Dakota Formation; and a ten-sack plug is set at the surface. If the casing is pulled, 100-foot plugs are placed spanning the casing top and the bottom of the surface casing. Field inspectors must witness every plugging.

References

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OHIO

INTRODUCTION

Ohio produced 14,987,592 barrels of oil and 182.2 x 10^9 cubic feet of gas in 1985 from 2,798 full-producing oil wells and approximately 26,412 stripper wells producing less than 10 barrels per day, and 31,343 gas wells, almost all of which were stripper wells producing less than 60,000 cubic feet per day.

REGULATORY AGENCIES

Two agencies regulate oil and gas activities in Ohio:

- Ohio Department of Natural Resources; and
- Ohio Environmental Protection Agency.

The Ohio Department of Natural Resources, Division of Oil and Gas, issues permits for oil and gas drilling and for underground produced water injection. The statutes and rules of the Division of Oil and Gas do not contain provisions for effluent discharges. The Division operates on revenues from permit fees and severance taxes on oil and gas. Enforcement activities are dependent primarily upon about 50 field staff employees who inspect well sites and conduct investigations. The Division of Oil and Gas has authority to review, investigate, and require corrective action related to all oil and gas drilling and production activities. Compliance bonds are required by the Division.

Ohio has been delegated NPDES authority. NPDES permits are issued through the Ohio Environmental Protection Agency, Water Quality Division; none are issued for the oil and gas drilling and production industry.

The jurisdiction of the Ohio EPA extends to any pollution of the waters of the State. Where produced water spills may impair waters of the State, for example, the Ohio DNR and the Ohio EPA jointly coordinate damage assessment and corrective measures. When the potential for ground-water contamination exists, the Ohio Environmental Protection Agency may assist in the investigation, and joint charges may be filed with the Ohio Department of Natural Resources.

A five-member oil and gas Board of Review was created by statute within the Ohio Department of Natural Resources. Members of the Board, appointed by the Governor for five-year terms, consist of representatives of a major petroleum company, the public, independent petroleum operators, and individuals experienced in oil and gas law and in geology. Any person claiming to be aggrieved or adversely affected by an order of the Chief of the Division of Oil and Gas may appeal to the Board for an order vacating or modifying such an order.

On occasion, there is oil and gas drilling on Federal lands. When an application for such drilling is filed, the permittee obtains a lease from the appropriate Federal authority prior to requesting a permit from the Division of Oil and Gas. The permitting process then is managed as a standard procedure with no special coordinating efforts.

STATE RULES AND REGULATIONS

Drilling

Earthen pits may be used to contain produced water, drilling muds and cuttings, fracture fluids, or other substances "resulting, obtained or produced in connection with drilling, fracturing, reworking, reconditioning, plugging back, or plugging operations, but such pits shall be constructed to prevent the escape of brine and such substances." There is no requirement for clay or synthetic liners, unless prescribed on a site-specific basis in an area identified as being hydrogeologically sensitive. When a history of ground-water problems is associated with an area, a plastic liner requirement is made part of the drilling permit.

The pits must be emptied and backfilled within 5 months of the commencement of drilling. The regulations specify that "muds, cuttings, and other wastes shall not be disposed of in violation of any rule." In most cases, pit solids are buried on the well site when no environmental harm is expected. Drilling fluids are disposed of by either underground injection or land application.

Produced Waters

Recently enacted laws, which became effective on April 12, 1985, established new standards for well operators and waste produced water transporters. Produced water disposal has been a major environmental issue in Ohio. Well drillers now are required to submit a produced water disposal plan stating the temporary storage method and ultimate disposal method and the site for all produced water.

Operators are required to identify the transporter of the produced water including the transporter's address. Anyone who transports produced water must pay a $500 one-time fee, provide a $300,000 certificate of insurance for bodily injury and liability, post a $15,000 bond to be used in paying for damages, and provide detailed information. This information includes a daily log that identifies the ultimate produced water disposal such as the time and date of produced water loading and the amount, roadspreading location, disposal well permit number, time and date of produced water disposal, etc. The driver must maintain a daily log showing driver name, registration certificate number, sites visited, and destination.

Produced water production is estimated at 40,000 to 50,000 barrels per day. Recent reports indicate that approximately 90 percent of produced water is disposed of through injection wells, 10 percent by surface application and annular disposal.

Storage/Disposal Pits

Under the requirements of the revised rules legislated in April 1985, "no pit or dike shall be used for the ultimate disposal of produced water." Earthen impoundments may be used for the temporary storage of produced water in association with a saltwater injection or enhanced recovery well.

Roadspreading

For roadspreading or landspreading, a county, township, or municipal government must pass a resolution to allow produced water disposal that meets several minimum requirements:

- Prohibitions on produced water application to a water-saturated surface, to vegetation, within 12 feet of bridges or other road surfaces crossing bodies of water or drainage channels, or during the night (except for ice control);
- Regulations on the rate, amount, and methods of application; and
- A prohibition against discharge by the vehicles making the application at any points other than the surfaces specifically approved.

A resolution with these minimum required specifications will be deemed approved when submitted to the Division of Oil and Gas, without any requirement for further review or approval by the Division.

Injection

Ohio has delegated authority for Class II well injection. Produced water may be injected into wells for enhanced recovery (170 wells), into disposal wells (182), or into the annulus of a producing well (approximately 4,000 wells). Permits are required for injection into disposal wells or enhanced recovery wells. Notification and approval are required for annular disposal.

For disposal and enhanced recovery wells, surface casing must be set at least 50 feet below the deepest underground source of water containing less than 10,000 mg/L TDS or less than 5,000 mg/L chlorides, and must be cemented to the surface. Surface casing must be cemented to the surface or properly sealed with prepared clay. Injected fluids must be isolated by the use of casing mechanically centralized and enclosed in cement to a height of no less than 300 feet above the top of the injection zone. Injection must be through tubing and a packer set no less than 100 feet above the injection zone.

A variance from some construction requirements may be granted if the injected volume is less than 25 barrels/day at minimal pressures, or if the chief determines that the variance sought will result in the construction of an injection well equivalent in its ability to protect freshwater aquifers.

Prior to any injection, the casing outside the tubing must be pressure tested at 300 psi or at the maximum allowable pressure, whichever is greater, for a period of 15 minutes, with no more than a 5 percent decline in pressure. The mechanical integrity test must be readministered at least once every 5 years.

The maximum volumes that can be disposed of with annular injection are 10 barrels per day (if the surface casing is sealed with cement) or 5 barrels per day (if sealed with prepared clay). Annular disposal can use only the force of gravity. Only salt water and standard well treatment fluids can be disposed of in the annulus. When a well ceases to produce oil or gas, annular disposal must stop and the well must be plugged.

For annular disposal, the surface casing must be sealed with cement or clay and the sealing material circulated to the surface. The surface casing must be set at least 50 feet below the deepest underground source of water with less than 10,000 ppm TDS or 5,000 ppm chloride. Annular disposal systems must be airtight. Produced water can be disposed of by liquid-tight pipeline only at an annular disposal well. No trucking of produced water is permitted.

Mechanical integrity must be demonstrated for annular disposal wells at least once every 5 years, using tracer surveys, noise logs, temperature surveys, or other tests approved by the Division.

Offsite Disposal

When a history of ground-water problems exists, pit solids may have to be removed and transferred to an Ohio EPA-regulated disposal site. If there is a request to move pit solids to an offsite area, an EP-toxicity test for hazardous waste characteristics is required prior to transfer to a State-approved hazardous or nonhazardous landfill, as appropriate. Abandoned pits are investigated when alleged to be the cause of a ground-water problem. If found to contribute to such a problem, the owner of the pit must remove the solids and transport them to a State-approved solids disposal facility.

Plugging/Abandonment

In Ohio, enforcement of plugging regulations is split between two enforcement agencies. Wells plugged in noncoal-bearing townships must be plugged in accordance with rules adopted by the Ohio Division of Oil and Gas, while wells plugged in coal-bearing townships must be plugged in accordance with rules adopted by the Ohio Department of Industrial Relations, Division of Mines. Plugging rules adopted by the two agencies differ somewhat.

Any operator plugging a well must inform owners of the land on which the well is sited, owners of adjacent land, and mine owners of the intention to abandon the well. Plugging operations for dry holes must begin as soon as the hole is abandoned. Plugging operations for abandoned production or injection wells must begin "without undue delay after production, extraction, or injection operations have ceased." Temporary abandonment status will be granted for a period of 6 months if the well poses no environmental threat; remedial action must be taken to correct environmental threats before such status will be granted.

Surface casing cannot be pulled from a rotary drilled well. Surface casing can be pulled from a cable tool drilled well if the conductor pipe is left in place. Cement plugs must be placed from a minimum of 50 feet below the base to a minimum of 100 feet above the top of the lowest reservoir rock. If clay is used as the plug, the plug must extend 400 feet above the top of the reservoir. For each succeeding reservoir, until within 100 feet of the bottom of the surface casing, the requirements are identical for cement plugs; for clay plugs the required minimum height above the top of a reservoir is reduced to 200 feet. For freshwater zones, cement plugs must extend from 50 feet below to 100 feet above the zone. A cement plug must also be placed from 50 feet below grade level to 30 inches below grade level. If a clay plug is used, the plug must extend from 50 feet below the base of the freshwater zone to 30 inches below grade. All portions of the well that are not filled by the plugs are to be filled with mud-laden fluid.

After a well is abandoned, the operator must file, with the Division of Oil and Gas, a detailed report containing information about the plugging and the identity of witnesses to the plugging.

References

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Personal Communications:

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OKLAHOMA

INTRODUCTION

Oklahoma produced 153,250,000 barrels of oil and 1,996 x 10^9 cubic feet of gas in 1984. It ranked fifth in U.S. oil production and third in U.S. gas production. Oklahoma had 99,030 producing oil wells and 23,647 producing gas wells. Approximately 200 million barrels of salt water are produced by the oil industry per year. There are about 7,900 saltwater disposal wells and 14,900 enhanced recovery injection wells. About 200 of the disposal wells are commercial facilities.

REGULATORY AGENCIES

Four agencies regulate oil and gas activities in Oklahoma:

- Oklahoma Corporation Commission, Oil and Gas Conservation Division;
- Oklahoma Water Resources Board;
- Osage Indian Tribe (in Osage County); and
- U.S. Bureau of Land Management.

The Oklahoma Corporation Commission, Oil and Gas Conservation Division, has exclusive jurisdiction over all laws and regulations "relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing and storage of oil and gas...." Pollution of surface or subsurface water during any well activity is prohibited. Currently, 55 inspectors have the authority to shut down operations if regulations are not followed. Oklahoma has received primacy for the UIC program, and the Division is responsible for the permitting and regulation of Class II wells.

The Oklahoma Water Resources Board is responsible for the protection of all surface and ground water to ensure that pollution does not occur. The Board has permitting authority for all discharges, which must meet specified water quality standards, including beneficial use limits. However, discharges to water from oil and gas activities are not allowed. The principal role of the Board in oil and gas drilling/production activities is to identify spills from oil and gas activities and refer them to the Corporation Commission for further action. On occasion, the Board will participate with the Commission in cleaning up the spills.

The Osage Indian Tribe has sole primacy regarding oil and gas operations in Osage County, and has been delegated UIC program responsibility for Class II wells.

The U.S. Bureau of Land Management has primacy where both surface and mineral rights are owned by the Bureau or by an Indian tribe other than the Osage Tribe. In these cases where the mineral rights, but not the surface rights, are owned by the Bureau or an Indian tribe, both the Bureau and the Oklahoma Corporation Commission would become involved and would coordinate the permitting procedures.

STATE RULES AND REGULATIONS

Drilling

Pit Construction/Management

Commission Rule 3-104 establishes a general requirement that "pits and tanks for drilling mud or deleterious substances used in the drilling, completion, and recompletion of wells shall be constructed and maintained so as to prevent pollution of surface and subsurface fresh water." It further requires that deleterious fluids other than freshwater drilling muds from drilling and workover operations be kept separate from the freshwater muds, and be placed in lined pits (plastic liner of at least 30 mil) or metal tanks for separate disposal.

Emergency pits, burn pits, and circulating, fracturing, or reserve mud pits used for drilling, reworking, or plugging a well may be constructed on site (serving only the lease or unit on which they are located) without a permit. Notices of construction must be filed, however, for emergency and burn pits (Rule 3-110.1).

Other than the general restriction against pollution, the only requirements applying to reserve pits as well as other onsite pits are that they must maintain the fluid level at least 18 inches below the lowest point of the embankment, and they must be constructed to prevent incursion of outside runoff water.

Pit Closure

Reserve pits must be dewatered and leveled within 12 months of the end of drilling operations. A single 6-month extension may be granted for reasonable cause. Circulating pits must be leveled within 60 days after drilling ceases, and fracture pits within 60 days after completion of fracture operations.

Disposal

Four methods are used to dispose of drilling fluids: annular injection, evaporation followed by burial of pit solids, noncommercial landfarming, or vacuum truck removal to offsite pits. Commercial landfarming is currently prohibited, but is under consideration by the Oklahoma Corporation Commission.

Annular Injection

An operator must apply for approval of onsite annular injection of reserve pit fluids. Surface casing injection (or intermediate casing injection) may be authorized if the surface casing (or intermediate casing) is set and cemented (set) at least 200 feet below the base of treatable water. Injection pressure must be limited so that vertical fractures will not extend to the base of treatable water (Rule 3-312).

Landfarming

Permits (required) for noncommercial soilfarming can be applied for only by the operator of the reserve pit, the contents of which are to be landfarmed (Rule 3-110.3). To apply for a soilfarming permit, the operator must have a written agreement from the landowner that is consistent with the regulatory requirements, an analysis of the soil, an analysis of the reserve pit contents, and loading calculations to determine the maximum number of barrels/acre that can be landfarmed. Permits expire 6 months after approval.

Pit contents must be applied uniformly by injection or spray irrigation and incorporated into the soil (within 14 days of application) by injection or disking. The Commission may approve other methods.

An effort must be made to re-establish vegetative cover within 120 days of the completion of soilfarming.

Soilfarming is limited to water-based muds and the cuttings and accumulated precipitation in the pit of oil-based muds. Soilfarming of oil-based muds is prohibited.

Generally, landfarming is not allowed unless receiving soils are suitable and the hydrology will not lead to pollution of surface or ground waters.

Specifically, landfarming is prohibited where:

- The land has a slope greater than 5 percent;
- The depth to bedrock is less than 20 inches;
- Floods occur more often than once every 2 years;
- The soil lacks 12 inches of loam, clay, silt, or sand;
- Any of the soil is severely saline (>8,000 micromhos/cm); and
- A water table is within 6 feet of the soil surface.

When soilfarming is permitted, it must be at least 100 feet away from property line boundaries, freshwater ponds or lakes, and streams designated by Oklahoma Water Quality Standards; at least 50 feet from any natural drainageway; 300 feet from any domestic or irrigation water well; and 800 feet from any active municipal water well.

The maximum application rate for soilfarming is determined by the most limiting of the following parameters:

Total weight of applied materials	400,000 lb/acre
Total soluble salts	6,000 lb/acre (less TSS in soil)
Arsenic	80 lb/acre
Cadmium	5 lb/acre
Hydrocarbons	100,000 lb/acre (5% by weight).

If hydrocarbon content is in excess of 20,000 lbs/acre (1 percent by weight), fertilizer may have to be incorporated with the cuttings and reserve pit effluent from oil-based drilling fluids.

Runoff of soilfarmed material prior to incorporation is prohibited. Soilfarming may not be practiced in winds gusting over 30 mph, in rain, when the ground is frozen, or when the ground is too highly saturated.

Produced Waters

<u>Injection</u>

Produced waters are injected underground for both enhanced recovery (14,900 wells) and disposal (17,700 onsite and 200 commercial wells). Permits are required from the Commission for all such wells, whether new or converted.

Neither enhanced recovery injection wells nor disposal wells are permitted within one-half mile of an active or reserve municipal water supply well unless the applicant can "prove by substantial evidence" that the injection well will not pollute the municipal water supply. In addition, the applicant may be required to provide information on the present status of all active or abandoned wells within one-half mile of the enhanced recovery or disposal well, and to identify any abandoned wells that were improperly plugged or remain unplugged.

Wells must be constructed and operated to confine injected fluids to the approved intervals and to prevent pollution of fresh water or damage to oil or gas resources. Surface casing or a stage collar must be installed to at least 90 feet below the surface or 50 feet below any treatable water strata, whichever is lower, and the annular space behind the casing must be filled with cement from the base of the surface casing or stage collar to the surface. (Alternative casing and cementing methods are permissible under some circumstances.)

Substances must be injected or disposed of through tubing and packer. Adequate aboveground extensions should be installed in each annulus in the well. Appropriate fittings must be provided to allow for measurement of injection pressure.

Before wells for disposal or enhanced recovery can be operated, they must be pressure tested under the supervision of the Conservation Division. For new wells, the casing outside the tubing must be tested at the maximum authorized injection pressure or 300 psi, whichever is greater. For converted wells, the test must be at the lesser of 1,000 psi or the maximum authorized injection pressure, but no lower than 300 psi. Test duration is 30 minutes.

With the exception of operators who elect to monitor their wells, each disposal or enhanced recovery well must be pressure tested at least once every 5 years. The casing-tubing annulus above the packer must be tested at 1,000 psi or the maximum authorized injection pressure, whichever is lower, with a minimum of 300 psi. In lieu of such a casing pressure test, the operator may, each month, monitor and record the pressure in the casing-tubing annulus during actual injection, and report the pressure annually (Rules 3-206, 3-301 through 3-309, 8-8).

Offsite Disposal

Under Rule 3-110.2, the Oklahoma Corporation Commission permits the use of offsite earthen pits. Such pits must be constructed or sealed with an impervious material, and must be operated in such a way as to prevent the escape of any deleterious material. The operator must provide a bond or irrevocable letter of credit as guarantee that the pit will be emptied and leveled "upon termination of disposal activities."

Some offsite pits service individual wells in situations where pits are not allowed at the site of the well (e.g., wells within city limits, where city ordinances prohibit such pits). However, there are also approximately 100 commercial offsite pits throughout Oklahoma, ranging from less than an acre to 10 acres in size. Some offsite pits may contain over 3,000,000 barrels of waste, which calculates to 387 acre/feet of fluids.

For any commercial pit, a qualified engineer must prepare a plan for site selection, construction, and closure. Commercial pits must have a soil seal at least 12 inches thick, with permeability no greater than 10^{-7} cm/second. If the pit contains deleterious substances, it must be lined according to specifications determined by the Commission. The pit must not contain fluids with a chloride content greater than 3,500 ppm, and may be sampled periodically to enforce that limit. The pit cannot be built in a 100-year flood plain, must be built to prevent incursion of outside water runoff, and must be managed to maintain the surface fluid level 36 vertical inches below the lowest point of the embankment. Such pits must be filled and leveled within 1 year after abandonment.

Truckers hauling oil and gas field wastes offsite must hold a Deleterious Substance License, but do not have to report or maintain records on materials and volumes transported.

Commercial Landfarming

Under an order of the Corporation Commission, issued in June 1987, commercial landfarming is permitted, provided the operator has obtained a Commission Order to Landfarm a specific trade, and receives a permit for each application of waste. Many of the requirements for commercial landfarming are similar to those for noncommercial landfarming, but some are more stringent. The least vertical distance to ground water from a commercial operation, for example, must be 25 feet; for noncommercial landfarming, only 6 feet is required. The maximum application rates for commercial landfarming are:

Total day weight of applied material	400,000 lb/acre
Total soluble salts	6,000 lb/acre (less TSS in soil)
Arsenic	80 lb/acre
Cadmium	5 lb/acre
Chromium	40 lb/acre.

Plugging/Abandonment

Wells in which neither surface nor production casing has been run must be plugged within 72 hours after drilling or testing is completed. If only surface casing has been run and cemented, plugging must take place within 90 days. In either case, however, if there is any risk of contaminating the environment, oil or gas formations, or treatable water strata, the well must be plugged within 24 hours.

Where production casing has been run, a well must be plugged within 1 year after the cessation of drilling (if not completed or tested), after the cessation of the latter of completion or testing (if no production), or after the cessation of production. There are, however, numerous exemptions from this requirement. Exemptions include shut-in gas wells, wells for which the Commission has issued an exception to plugging requirements (e.g., where production has ceased for economic reasons), and wells located on leases on which other wells are still producing (if they have been granted a Temporary Exemption by the Commission). Operators of stripper wells may plug a well temporarily for up to 2 years.

Plugging must provide for sealing off each productive formation from the wellbore above and below the formation. Cement plugs must extend from 50 feet below to 50 feet above the base of each formation, and from 50 feet below to 50 feet above the top of each formation. Exceptions to these requirements may be granted if: (a) the formation is already sealed off from the wellbore with adequate casing, and (b) the only openings from the productive formation are perforations in the casing, and the annulus between the casing and the outer walls of the well is filled with cement 50 feet below the base and 50 feet above the top of the formation. In such a situation, a bridge plug capped with 10 feet of cement set at the top of the producing formation is authorized.

All freshwater strata in the well must be sealed off by adequate casing from 50 feet below the base of the lowest freshwater stratum to 3 feet from the top of the wellbore, and by completely filling the annular space behind the casing with cement. If surface or other casing meets the requirements, a cement plug may be set 50 feet below the base of the lowest freshwater stratum to 50 feet above the shoe of the surface pipe. The top 30 feet of the wellbore below 3 feet from the surface must be filled with cement. The surface pipe must be cut off 3 feet from the surface and capped with a steel plate.

Any uncased hole below the shoe of any casing to be left in the well should be filled with cement to a depth of at least 50 feet below the shoe of the casing, or the bottom of the hole, and the casing above the shoe should be filled with cement to at least 50 feet above the shoe of the casing. If the well is completed with a screen or liner, and the screen or liner is not removed, the wellbore must be filled with cement from the base of the screen or liner to at least 50 feet above the top of the screen or liner.

All intervals between cement plugs in the wellbore must be filled with mud of not less than 9 lb/gal and not less than 36 viscosity.

All plugging operations must be conducted under the supervision of an authorized representative of the Conservation Division.

References

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Karen Dihrberg, Geologist, Water Resources Board (405) 271-2549.

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OREGON

INTRODUCTION

Oregon does not produce oil. Oregon's only producing gas field was discovered in 1979. Thirteen active gas wells produced 4.5 x 10^9 cubic feet of gas in 1986. There is one saltwater injection well for the field. In 1986, approximately 40,000 barrels of produced water were injected underground; about 5,000 barrels went to surface land disposal.

REGULATORY AGENCIES

Two agencies regulate oil and gas activity in Oregon:

- Oregon Department of Geology and Mineral Industries and
- Oregon Department of Environmental Quality.

Oil and gas drilling permits are issued by the Oregon Department of Geology and Mineral Industries. The State Geologist serves as the implementor of rules, orders, and enforcement actions taken by the Department's governing board. The Department is also responsible for regulating Class II wells.

The Oregon Department of Environmental Quality has delegated authority for the NPDES program and issues UIC permits. The State has maintained a permitting program since 1968. No NPDES permits have been issued because there have been no requests to discharge waste to public waters.

None of the gas wells are on Federal lands. If drilling were to take place on Federal lands in the future, there would be two separate permitting actions--one by the U.S. Bureau of Land Management and one by the Oregon Department of Geology and Mineral Industries.

STATE RULES AND REGULATIONS

Drilling

Oregon Administrative Rule 632-10-205 requires a surety bond of up to $25,000 for one well or a blanket bond of $150,000 for more than one well, conditioned upon the faithful compliance by the principal with the rules, regulations, and orders of the Department of Geology and Mineral Industries.

Rule 632-10-140 requires that any fluid necessary to the drilling, production, or other operations by the permittee be discharged or placed in pits and sumps approved by the State Geologist and the State Department of Environmental Quality. The operator must provide pits, sumps, or tanks of adequate capacity and design to retain all materials. In no event should the contents of a pit or sump be allowed to:

1. Contaminate streams, artificial canals or waterways, ground waters, lakes, or rivers; or
2. Adversely affect the environment, persons, plants, fish, and wildlife and their population.

When no longer needed, fluid in pits and sumps must be disposed of in a manner approved by the Department of Environmental Quality. In addition, the sumps must be filled and covered and the premises must be restored to a near natural state. The restoration need not be done if arrangements are made with the surface owner to leave the site suitable for beneficial subsequent use.

Drilling mud pits are not allowed to hold over the winter because of lack of sufficient storage for winter rainfall. If drilling muds dry in the reserve pits before winter arrives, the pit is then closed.

There has been no problem with abandoned pits; the surety bond provides a mechanism to ensure adequate pit closure.

Production

Rule 632-10-192 of the Department of Geology and Mineral Industries provides that brines, or saltwater liquids, may be:

1. Disposed of in pits only when the pit is lined with impervious material and a Water Pollution Control Facility permit has been issued by the Department of Environmental Quality. Earthen pits used for impounding brine or salt water shall be so constructed and maintained as to prevent the escape of fluid.
2. Disposed of by injection into the strata from which they were produced or into other proved saltwater-bearing strata.
3. Disposed of by ocean discharge, which may be permitted if water quality is acceptable and if such discharge is approved by the State Department of Environmental Quality through issuance of an NPDES waste discharge permit.

Produced brines are permitted to be spread on dirt roads--predominantly logging roads--if done in dry weather.

Offsite Disposal

There are no operational offsite pits. One dumpsite has been used as an emergency pit. Operators must dispose of drilling muds in a Department of Environmental Quality-approved solid waste disposal site. Such solids may be tested prior to disposal to determine if they contain hazardous materials.

Plugging/Abandonment

The State Geologist may authorize suspension of operations for good cause for whatever time period is stated in the written authorization, and further extensions may be granted upon expiration of the authorization.

According to Rule 632-10-198, when a well is plugged, producing strata and strata with fluid at greater than hydrostatic pressure must be plugged with cement from 50 feet below to 50 feet above each stratum. A 100-foot cement plug must be placed across the base of the freshwater-bearing strata, when it is in open hole. When there is an open hole below the base of any casing, a cement plug must extend from 50 feet below to 50 feet above the base of the casing. All casing strings must be cut off at least 4 feet below the ground and plugged with cement to a depth of 10 feet. Intervals between plugs must be filled with heavy, mud-laden fill.

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PENNSYLVANIA

INTRODUCTION

Pennsylvania produced 4,825,000 barrels of oil and 166 x 10^9 cubic feet of gas in 1984. Production was from 20,739 oil wells and 24,050 gas wells.

Until 1955, requirements for the oil and gas industry were minimal if not nonexistent. State laws did not require permitting or registration of oil and gas wells. In 1961, the statutes were strengthened to prohibit wasting in production wells, establish spacing, and provide other requirements. It was not until 1984 that the Coal and Gas Resources Coordination Act and the Oil and Gas Act made sweeping changes in permit review and requirements. There had been little uniformity in Pennsylvania oil and gas laws until then. Combined, these statutes enable Pennsylvania permitting authority to put terms and conditions on permits and to deny permits. House Bill 1375, passed in mid-September 1986, further strengthens the regulatory management of the oil and gas industry in Pennsylvania and requires the development of new regulations relating to solid waste management and the disposal of wastes onsite.

The first commercial oil well in the United States was drilled near Titusville, Pennsylvania, in 1859.

REGULATORY AGENCIES

Five agencies regulate oil and gas activities in Pennsylvania:

- Department of Environmental Resources, Bureau of Oil and Gas Management;

- U.S. Environmental Protection Agency, Region III:
- Pennsylvania Fish Commission:
- U.S. Forest Service: and
- U.S. Bureau of Land Management.

The Bureau of Oil and Gas Management was created in 1984 to coordinate and combine all related regulatory activities of the oil and gas industry. The Oil and Gas Conservation Law, enacted in 1961, established powers and duties of the Oil and Gas Conservation Commission. Those powers and duties were transferred to the Department of Environmental Resources in 1970. Section 216 of the Oil and Gas Act of 1984 created an Oil and Gas Technical Advisory Board to advise the Department in regulatory activities. The five-member board consists of three representatives of the oil industry, one from the Citizen's Advisory Council, and one from the coal industry.

Section 207(a) of the Act requires that the disposal of drilling and production brines be consistent with the requiremehts of the Clean Streams Law (which was first passed in 1937 and was most recently amended in 1980). Section 208(a) requires that any well owner who affects the public or private water supply by pollution or diminution shall restore the affected supply or replace it with an alternative source. Section 205 prohibits the drilling of wells within 200 feet of buildings or water wells without the consent of the owner, within 100 feet of any body of water, or within 100 feet of a wetland 1 acre or more in size. There is a compliance bond conditioned upon the operator's faithful performance of the drilling, restoration, water supply replacement, and well plugging requirements of the Oil and Gas Act.

The U.S. Environmental Protection Agency, Region III, issues UIC program permits for underground injection and secondary recovery. The Bureau of Oil and Gas Management has not sought primacy in the UIC program.

The Pennsylvania Fish Commission seeks out pollution of surface waters and takes appropriate action under the Pennsylvania Fish and Boat Code.

Requirements of the U.S. Forest Service and the U.S. Bureau of Land Management are contained in lease agreements. The well driller must demonstrate that landowners and water supply owners have been notified of the intent to drill. Mineral rights in the Allegheny National Forest are privately owned. The Bureau of Oil and Gas Management issues drilling permits on Federal lands.

STATE RULES AND REGULATIONS

Drilling

• Drilling pits to the present time have been virtually unregulated. Pits typically are unlined. Such pits contain drilling cuttings, contaminated fresh and salt water produced during construction and well stimulation, and various additives used during drilling and well stimulation. Pits are not reclaimed and no permit is required for a drill pit. There is no contingency fund for the management of abandoned pits. The Bureau is in the process of developing regulations to further control oil and gas operations. The thrust on drilling pits is to remove liquids to offsite and commercial treatment and disposal facilities and to dispose of solid wastes onsite with pit reclamation. Presently, however, many pits remain onsite and may be used for oil/water separation during the production phase.

Production

It has been estimated that Pennsylvania has 17,000 impoundments associated with oil and gas produced waters. If an impoundment is associated with an individual well, a permit has not been required.

Permits are required for offsite and commercial treatment systems. The trend since 1985 has been to move in the direction of centralized treatment facilities for oil and gas waste materials. However, only a few facilities within the State presently operate to treat solely production wastewaters.

Other production fluid disposal alternatives are discussed in the Oil and Gas Operator's Manual published by the Bureau of Oil and Gas Management. As the Manual notes, the practices suggested are options, not regulations. Alternatives include the following:

- Disposal wells;
- Annular disposal;
- Treatment and discharge to surface waters;
- Onsite treatment and land disposal of top hole water;
- Discharge to existing treatment facility;
- Road spreading; and
- Evaporation (through waste heat).

Since these alternatives are not binding regulations, it is largely left to the operator to choose acceptable techniques for disposal

Offsite Disposal

Water Quality Management Part II permits and NPDES permits are required for treatment facilities that discharge to waters of the Commonwealth. Treatment afforded production fluids may include flow equalization, pH adjustment (if necessary), gravity separation and surface skimming, retention and settling, and aeration. The discharges from several offsite produced-fluids treatment facilities may be covered under a single NPDES permit if the management of those facilities is under the control of one owner/operator and the geographic area is such as to allow for effective monitoring and surveillance.

The NPDES permit criteria and limits will be governed by receiving water quality standards. Generally, however, total suspended solids will be limited to an instantaneous maximum of 60 mg/L and an average monthly of 30 mg/L. Oil and grease will be limited to an instantaneous maximum of 30 mg/L and an average monthly of 15 mg/L. Dissolved iron has an instantaneous maximum of 7 mg/L, and the acidity must be less than the alkalinity.

Plugging/Abandonment

If wells are certified as having future utility and are in adequate condition to prevent a vertical flow of fluids, contamination of fresh water, or damage of productive zones, a permit can be issued for inactive status. The permit is valid for 5 years and is renewable.

While revised regulations on plugging are to be adopted under the new law, current requirements under Act 225 (as amended by Act 265 of 1968) are that: (1) cement plugs of at least 20 feet should be set 20 feet above each stratum that has had oil, gas, or water; (2) a bridge capped with 10 feet of cement should be placed 30 feet below the water string of casing, after which the casing may be drawn; (3) a plug should be placed about 10 feet below the bottom of the largest casing in the well; and (4) all the spaces between the bottom or top of the well and cement plugs, or between the cement plugs, should be filled with sand pumpings, mud, or other equally nonporous material. Additional plugging requirements are specified for wells passing through workable coal seams and for wells where the operator wishes to pull the casing. Additional recommendations are made in the Oil and Gas Operator's Manual published by the Bureau of Oil and Gas Management.

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SOUTH DAKOTA

INTRODUCTION

South Dakota produced 1,342,237 barrels of oil and 2.5 x 10^9 cubic feet of gas in 1984. The State has 145 full production and 33 stripper oil wells, and 41 full production gas wells and 1 marginal production gas well.

REGULATORY AGENCIES

These four agencies regulate oil and gas activities in South Dakota:

- South Dakota Department of Water and Natural Resources;
- South Dakota Department of School and Public Lands;
- U.S. Bureau of Land Management; and
- U.S. Environmental Protection Agency, Region VIII.

The South Dakota Department of Water and Natural Resources is the primary regulatory agency for oil and gas operations through its Oil and Gas Program in the Division of Environmental Quality. The primary enforcement agency for the UIC program, which also has nondelegated responsibility for NPDES compliance, is the Department's Office of Water Quality. The Department of Water and Natural Resources also houses the Board of Minerals and Environment, which has the power to conduct hearings and take action on other oil and gas program-related enforcement measures.

South Dakota has not been delegated NPDES authority. Two of the active wells have NPDES permits because of beneficial use associated with wastewaters. Draft NPDES permits are prepared by the State and issued by the Water Management Division, U.S. Environmental Protection Agency, Region VIII.

In order to drill on Federal lands, two applications for drilling would be filed--one with the State Department of Water and Natural Resources and one with the U.S. Bureau of Land Management. The State would defer to the Bureau regarding any predrilling permit investigation. Two permits, one from each entity, would be issued to the driller. When a request to inject drilling fluids underground is received, the Bureau would defer to the State, and the State would issue the injection permit. Since the Bureau has no means of holding hearings, the State Board of Minerals and Environment would do so prior to permit issuance.

The South Dakota Department of School and Public Lands has enforcement powers for lease compliance on State-owned lands and for State-owned minerals.

STATE RULES AND REGULATIONS

Drilling

When drilling operations cease, supernatant fluid in the drilling pit is allowed to evaporate and the mud is allowed to dry. The time interval required for this to occur is a various and unknown factor. When the mud has dried sufficiently, the pit is buried and the surface is reclaimed to natural conditions.

The Department of Water and Natural Resources requires a Plugging and Performance Bond for wells and a Surface Restoration Bond.

Production

Discharge of produced wastes is permitted to total retention-evaporation ponds, to Class II UIC wells, and for beneficial use. There are no specific requirements related to pit construction, but the State is currently considering a proposal to require pits to have liners or to be of impermeable construction.

Discharge of produced water from a producing oil well is allowed when a beneficial use of the water can be documented. An NPDES permit is required for such a discharge. The two NPDES-permitted discharges from wells in South Dakota are used for stock watering. NPDES permits contain not-to-exceed limits for oil and grease of 10 mg/L, total dissolved solids of 5,000 mg/L, and a pH of 6.0 to 9.0. The flow is not to exceed 4,500 gallons per day.

Offsite Disposal

There are no offsite pits in use, but if there were a request for such usage, the request would be managed through the solid waste permitting process under the Board of Minerals and Environment.

Plugging/Abandonment

A well may be classified as temporarily abandoned for a period of 6 months for good cause, and this status may be extended on a case-by-case basis.

Wells must be plugged when they can no longer fulfill the purpose for which they were drilled. Plugging must follow scheduling and requirements approved by the State Geologist.

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TENNESSEE

INTRODUCTION

Tennessee produced about 937,000 barrels of oil from 798 wells in 1984. Only 54 oil wells produced more than 10 barrels of oil per day. Of 507 gas wells, 474 produced less than 60 thousand cubic feet per day.

Regulation of oil and gas drilling operations began in 1968. Wells drilled prior to 1968 do not have to be permitted unless they are deepened, reopened, or reentered.

REGULATORY AGENCIES

Three agencies regulate oil and gas activities in Tennessee:

- State Oil and Gas Board;
- Tennessee Department of Health and Environment; and
- U.S. Department of the Interior, Bureau of Land Management.

The State Oil and Gas Board of the Tennessee Department of Conservation is authorized by the Tennessee Code Annotated (Revised 1982) to regulate activities related to the production of oil and gas in Tennessee. The State Oil and Gas Board regulates the industry according to the General Rules and Regulations (Tennessee State Oil and Gas Board Statewide Order No. 2). The State Oil and Gas Board issues drilling permits and regulates surface disposal.

The Department of Health and Environment is the NPDES authority in Tennessee. It does not currently have UIC primacy but is working toward being granted primacy by EPA. Discharges of oil and gas wastes are not permitted by the Tennessee Department of Health and Environment.

The U.S. Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service.

STATE RULES AND REGULATIONS

Drilling

Much of the drilling in Tennessee is air drilling. The most common types of wastes in drilling pits are foaming agents used during the drilling process and spent acids from well treatments.

Before an applicant can complete the permit process and begin to drill, one of the Board's inspectors must approve all pollution control structures, including pits, dikes, diversion drainage ditches, and tanks. In addition, during drilling, inspectors are required to monitor casing programs, particularly with respect to circulation of cement behind the surface casing to reduce the likelihood of ground-water contamination.

The Board requires operators to drain surface pits of water and backfill them with dirt immediately after they are no longer needed for drilling or testing.

Produced Water

Produced salt water may be disposed of by discharge into an evaporation pit, by annular injection, or by disposal into a dedicated disposal well. In addition, produced water could be used for injection in an enhanced recovery project. The use of evaporation pits is acceptable where both the method and the pit have been approved by a representative of the Board. According to information provided by the Board, it is now the Board policy to require the lining of pits, particularly in areas where produced water will be the major constituent of the fluids in the pit. The policy was adopted to prevent contamination of ground water from percolation of pit fluids.

An operator may obtain a permit for annular disposal of produced water for a year. Water injected into the annulus must not be allowed to enter formations with oil, gas, or fresh water.

Plugging/Abandonment

Dry wells must be plugged within 6 months after drilling is finished, with an extension of 90 days for good cause. Gas wells that pass a deliverability test may be classified as shut-in indefinitely. Wells no longer used for the purpose for which they were drilled or converted must be plugged. Wells that are neither producing nor plugged must be cased and capped to protect oil, gas, and fresh water. Cash bonds are required for all wells being temporarily abandoned.

When plugged, wells must be filled with sufficient mud to offset the hydrostatic pressure of any formation penetrated. Adequate plugs must be placed to prevent the commingling of fluids and to isolate extractable minerals.

References

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TEXAS

INTRODUCTION

In 1985, Texas produced over 830 million barrels of oil from over 210,000 wells. Gas production was 5,805 billion cubic feet from 68,811 gas wells. It is estimated that 75 percent of all active Texas wells are marginally producing wells.

Regulation of the oil and gas industry in Texas began when the Railroad Commission was assigned jurisdiction over oil and gas activities in 1919.

REGULATORY AGENCIES

•The following agencies have jurisdiction over the disposal of oil and gas wastes in Texas:

- Texas Railroad Commission;
- Texas Air Control Board;
- Texas Parks and Wildlife Department;
- U.S. Army Corps of Engineers; and
- U.S. Environmental Protection Agency

Oil and gas activities in Texas are regulated almost entirely by the Oil and Gas Division of the Railroad Commission. The Railroad Commission is responsible for the prevention of both waste and pollution. Thus, one agency is responsible for well spacing, construction requirements (casing, etc.), and most aspects of environmental protection.

In 1985, the Texas legislature amended Section 91.101 of the Natural Resources Code, as well as Section 26.131 of the Water codes, to make explicit the scope of authority of the Railroad Commission with respect to activities related to the exploration, development, and production of oil and gas. It specified that production activities include activities associated with natural gas or natural gas liquids processing plants and activities associated with the storage, handling, reclamation, gathering, transportation, or distribution of oil and gas prior to the refining of the oil or the use of the gas. It also specifically included within the jurisdiction of the Commission the drilling of injection-water source wells that penetrate the base of usable quality water. These wells produce water to be used in enhanced recovery injection wells. The major change in the statute was the specification of activities that were to be considered related to "production."

Statewide Rule 8 (governing "water protection") of the Railroad Commission was amended effective January 6, 1987, to incorporate these changes in the Natural Resources Code.

The Railroad Commission issues permits for any discharges related to oil and gas exploration, development, and production activities. Since the State currently does not have NPDES jurisdiction, such discharges are also subject to EPA permitting.

The Railroad Commission has jurisdiction over Class II underground injection wells and has undertaken a study to determine the need for a Class I well program for wells under its jurisdiction, specifically wells used for the injection of gas plant wastes. Currently, all injection of gas plant wastes in Texas is subject to Class II requirements. The preliminary results of the Commission's study indicate that gas plant injection wells in the State meet Class II well criteria.

The Texas Air Control Board has jurisdiction over the regulation of oil field activities generating air emissions.

The Texas Parks and Wildlife Department, Pollution Surveillance Branch, investigates fish kills and water pollution complaints and evaluates the effects of discharged wastes on fish and wildlife. The Texas Parks and Wildlife Department has statutory authority to recover the monetary value of damaged fish and wildlife. The Parks and Wildlife Department may also enforce the Texas Water Code when permit violations, discharges in excess of permit limitations, or discharges without a permit occur.

The Texas Railroad Commission has jurisdiction over oil and gas activities on Federal lands in Texas, regardless of who owns the mineral rights.

The U.S. Army Corps of Engineers has permitting responsibility for any activities that would affect wetlands subject to Section 404 of the Clean Water Act.

STATE RULES AND REGULATIONS

General

Texas Statewide Rule 8 prohibits any "person conducting activities subject to regulation by the [Railroad] Commission" from causing or allowing pollution of surface or subsurface waters in Texas. With limited exceptions (e.g., landfarming or burial of drilling fluids under specified conditions), "no person may dispose of oil and gas wastes by any method without obtaining a permit to dispose of such wastes." The exceptions are authorized in Rule 8, under conditions specified in the Rule. The Rule's "authorizations" thus serve the same function as "general permits" in some other States. Under Statewide Rule 9, permits are required for disposal of oil and gas waste by injection into formations not productive of oil or gas. Statewide Rule 46 requires permits for injection into productive formations.

Drilling

Pit Construction Permits

The Railroad Commission authorizes, by Rule, the maintenance and use without a permit of reserve pits, mud circulation pits, completion/workover pits, basic sediment pits, flare pits, fresh makeup water pits, and water condensate pits, provided that such pits are operated and closed as required by Rule 8. The use of reserve pits and mud circulation pits for oil and gas wastes is restricted to drilling fluids, drill cuttings, sands, silts, wash water, drill stem test fluids, and blowout preventer test fluids.

Permits are required for drilling fluid storage pits (other than mud circulation pits), drilling fluid disposal pits (other than reserve pits or slush pits), and any other pits not specifically authorized by the Rule. For pits requiring permits, pit locations are evaluated on a case-by-case basis to determine what construction requirements are necessary to prevent waste of oil and gas resources or pollution of surface water or ground water. Proposed unlined pits, which will be continuous-use saltwater pits, are also evaluated to determine whether these pits would cause pollution of surrounding productive agricultural land. The requirements may or may not include liners.

Pit Closure

The Railroad Commission requires that pits be dewatered, backfilled, and compacted for closure. Backfill requirements (for all types of pits) vary according to the type of pit and the chloride concentration of the pit contents. Reserve pits (and mud circulation pits) containing fluids with a concentration of over 6,100 mg/L chloride must be dewatered within 30 days of cessation of drilling operations. Reserve pits containing fluids with a concentration of 6,100 mg/L or less must be dewatered within a year. In both cases, backfilling must be carried out within a year of the cessation of drilling operations. Because of dewatering time limits, reserve pit fluids may need to be hauled offsite for disposal.

Completion/workover pits must be dewatered within 30 days and backfilled and compacted within 120 days of cessation of completion or workover operations.

Disposal

The Railroad Commission permits treatment and discharge of reserve pit fluids to land or to surface waters provided that the discharge does not cause a violation of Texas water quality standards. The Rule does not specify what processes constitute acceptable treatment technologies. The applicant for a permit may choose the technology, but must provide proof that the selected technology will meet the Commission's criteria. The criteria for discharges to surface waters are as follows:

- Chemical oxygen demand < 200 mg/L
- Total suspended solids < 50 mg/L
- Total dissolved solids < 3000 mg/L
- Oil and grease < 15 mg/L
- Chlorides (coastal) < 1000 mg/L
- Chlorides (inland) < 500 mg/L
- pH 6.0 to 9.0

- 24-hour bioassay in accordance with procedure developed by Texas Parks and Wildlife Department.

- Water color must be adjusted to match the receiving stream.

- Volume of the discharge must be "controlled so that a minimum 5:1 dilution of the wastewater by the principal receiving stream is maintained."

- Discharge cannot exceed concentrations of hazardous metals as defined by Texas Water Development Board Rules 156.19.15.001 - 156.19.15.009.

In coastal areas, if the receiving body of water has concentrations of TDS or chlorides in excess of 3,000 mg/L or 1,000 mg/L, respectively, then the concentration of the treated reserve pit fluids may exceed those limits, but may not exceed the levels in the receiving water body at the point and time of discharge. In such cases, the effluent must be piped to the receiving water body.

Rule 8 authorizes landfarming or burial of water-based drilling fluids and associated wastes that meet specific conditions. The authorizations do not extend to oil-based drilling fluids, which require a permit for disposal.

The authorization for landfarming applies where water-based drilling fluids have a chloride concentration equal to or less than 3,000 mg/L. Under the authorization, the wastes must be disposed of on the same lease where generated, and the operator must have the written consent of the landowner. Landfarming encompasses sprinkler irrigation, trenching, injecting under the surface, discing, and surface spreading by vehicles; the waste must be applied in such a way that it will not migrate off the landfarmed area.

Where the water-based drilling fluids have a chloride concentration in excess of 3,000 mg/L, but the wastes have been dewatered, burial is authorized at the well site where the waste is generated.

One-time disposal of reserve pit fluids down the annulus of a well is allowed, but requires a "minor permit" for each disposal incident.

Produced Fluids

More than 90 percent of produced waters are disposed of by injection, with most of the remainder disposed of in coastal ("tidally influenced") waters. Less than 1 percent is disposed of in pits.

Pits

Individual permits are required for produced water pits, collecting pits, skimming pits, emergency saltwater storage pits, and saltwater disposal pits.

A 1984 amendment to Rule 8 required the re-permitting or closure of all previously permitted lined or unlined pits for the storage or disposal of oil field produced waters. The 1984 amendment also required the permitting of other types of pits that did not have to be permitted prior to the amendment. With the exception of emergency saltwater storage pits. permits for unlined pits will be granted only if the operator can "conclusively" show that "use of the pit cannot cause pollution of surrounding productive agricultural land nor pollution of surface or subsurface water." Since the amendment, the Railroad Commission has received approximately 8,900 permit applications for all types of pits, half of which are for emergency saltwater storage pits used in connection with injection and storage wells. Of the 8,900 applications, 2,675 are for pits that were permitted prior to the amendment. As of December 1, 1986, the Commission had received 388 applications for saltwater disposal pits (unlined, because of the need for both evaporation and percolation for disposal purposes); 13 were approved, 233 denied, with the rest still under consideration. Approvals were largely for low-chloride (<500 ppm chloride) produced waters in areas where there was no possible impact on fresh subsurface water. The Commission expects to complete the processing of the 8,900 applications by late 1988.

Specific lining/monitoring requirements are determined on a case-by-case basis. Generally, all continuous-use pits (e.g., skimming pits) would require linings, as would emergency saltwater storage pits in sandy soils.

Injection

Class II injection wells are used both for enhanced recovery (36,368 wells) and disposal (16,404 wells). Requirements for Class II enhanced recovery wells are found in Rule 46 of the Texas Railroad Commission; requirements for Class II disposal wells are found in Rule 9.

The Commission requires that a newly drilled disposal well have surface casing set to fully protect underground sources of drinking water with cement circulated to the surface. Rule 9 stipulates that the well must be equipped with tubing set on a mechanical packer, set no higher than 100 feet above the top of the permitted injection interval.

Mechanical integrity tests must be conducted before injection begins, and at least once every 5 years thereafter. Most mechanical integrity tests are pressure tests. Test pressures must equal the maximum authorized injection pressure or 500 psig, whichever is less, but in no case less than 200 psig. Tests are acceptable if they are conducted at a pressure within 10 percent of the pressure required by the formula. However, once the casing pressure stabilizes, a test must be conducted for 30 minutes with no variation.

Specifications under Rule 46 for enhanced recovery wells are identical with respect to casing, the requirement for using tubing and packer, and mechanical integrity tests. The required setting for the packer is no higher than both 200 feet below the known top of cement behind the long string casing and 150 feet below the base of usable quality water.

Surface Discharge

The Railroad Commission allows discharge of produced water into coastal areas under individual permits. Sufficient collecting and skimming pits must be maintained to prevent any oil from entering the tidal waters. Random samples of the discharged produced water must be tested for oil content every 30 to 40 days.

Offsite Disposal

Transportation

Persons who transport produced water for hire (other than by pipeline) must hold a Salt Water Hauler Permit from the Railroad Commission. Haulers must keep a record of the volume of water transported, the property from which it originated, and the amount delivered to which specific disposal facility. Similar records must be kept by the producer. No requirements of this type are imposed on the transport of drilling fluids.

Disposal

All offsite disposal of oil and gas wastes requires individual permitting. The primary offsite facilities in Texas are disposal wells that receive materials by truck. There are approximately 200 Class II commercial wells in Texas.

In addition, there are approximately 100 central disposal pits for drilling fluids, 50 to 75 central drilling fluid landfarming facilities, and a few facilities for the treatment and discharge of drilling fluids in coastal areas. Management requirements for these facilities are determined on a case-by-case basis.

Plugging/Abandonment

Plugging procedures for dry or inactive wells that cease drilling or operations between January 1, 1986, and January 1, 1988, must commence within 1 year of the cessation of operations. (For other wells, the limit is 90 days.) In addition, a reasonable extension of time is available at the discretion of the Director of the Oil and Gas Division if the well does not present a pollution hazard and the operator has either posted a plugging bond or letter of credit, or presented a plan for further use of the well in enhanced recovery operations.

A well-plugging fund has been established to enable the State to plug abandoned wells. The major source of funding is provided by a $100 drilling permit fee for each new well.

Cement plugs should be set by the circulation or squeeze method through tubing or drill pipe, and should have sufficient volume to fill

100 feet of hole plus 10 percent for each 1,000 feet of hole from the ground surface to the bottom of the plug. All portions of the well not filled with cement must be filled with mud-laden fluids of at least 9.5 lb/gal.

For wells with surface casing, plugging requirements depend on whether the surface casing is set to protect all usable water quality strata. Where it does, a cement plug should be set to extend from at least 50 feet below to 50 feet above the shoe of the surface casing. Where the casing has been set deeper than 200 feet below the base of the deepest usable water strata, an additional plug, within the casing, must extend from at least 50 feet below the base to at least 50 feet above the top of the lowest such stratum. Where the casing does not afford such protection, a similar plug must be placed across the shoe of the surface casing, with another plug placed from at least 50 feet below the base to at least 50 feet above the top of the lowest usable water stratum.

For wells with intermediate or production casing that has been cemented through all usable quality water or productive horizons, a cement plug should be placed inside the casing and extend from at least 50 feet below the base to at least 50 feet above the top of the deepest usable quality water stratum. Where such casing has not been cemented through all strata and horizons, the casing must be perforated at the required depths to place cement outside the casing by squeeze-cementing. A plug should also be set above each perforated interval or open hole completion.

For wells without production casing and open hole completions, productive horizons or formations in which pressure or formation water problems exist should be isolated by plugs centered at the top and bottom of the formations. Such plugs are to be continuous if the formation is less than 100 feet thick.

The District Director may require additional plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation.

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UTAH

INTRODUCTION

Utah produced 38,053,871 barrels of oil from 1,862 wells in 1984. Approximately 20 percent of these wells are stripper wells. Utah produced 183,061,947 MCF of gas from 728 gas wells in 1984. This gas production volume includes recycled injection gas attributed mainly to pressure maintenance operations at the Anschutz Ranch East field.

REGULATORY AGENCIES

Four agencies share regulatory responsibility for oil and gas activities in Utah:

- Utah Department of Natural Resources, Division of Oil, Gas, and Mining;
- Department of Health, Bureau of Water Pollution Control;
- U.S. Bureau of Land Management (and possibly the Bureau of Indian Affairs); and
- U.S. Forest Service (surface rights only).

The Division of Oil, Gas, and Mining adopted new Oil and Gas Conservation General Rules effective December 2, 1985. These rules cover drilling and operating practices; UIC Class II injection well responsibility; and purchasing, transportation, refining, and rerefining. The Division of Health currently has regulatory authority over disposal ponds. The Department of Oil, Gas, and Mining is hoping to bring most aspects of oil and gas regulation under one agency by assuming authority for disposal ponds in the near future.

The U.S. Department of the Interior, Bureau of Land Management, has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service.

STATE RULES AND REGULATIONS

Drilling

Rule 308 of the Division of Oil, Gas, and Mining rules requires oil and gas operators to "take all reasonable precautions to avoid polluting streams, reservoirs, natural drainage ways, and underground water." This requirement is supported by a specific rule for reserve pits (Rule 309). "Salt water and oil field wastes associated with the drilling process may be disposed of by evaporation if impounded in excavated earthen reserve pits underlain by tight soil such as heavy clay or hard pan or lined in a manner acceptable to the Division." Pit liquids are not allowed to escape onto the land surface or into surface waters.

Since most of Utah has very rapid evaporation rates, the reserve pit supernatant is generally allowed to evaporate before pit closure. Final pit closure requirements were not found in the rules.

In areas of net precipitation, or in areas where pit construction is especially difficult (i.e., steep mountainsides), the Division may allow the reserve pit supernatant to be disposed of down the annulus of the new well into a properly confined zone of poor quality. This determination is made by the Division of Oil, Gas, and Mining on a case-by-case basis.

The Division of Oil, Gas, and Mining has extensive technical rules regarding well siting, casing requirements, and well drilling.

Production

Most produced water is injected for water flooding or for disposal. Utah has approximately 650 Class II injection wells, including about 45 active disposal wells. The Division of Oil, Gas, and Mining controls injection wells and onsite disposal facilities.*

The Utah Department of Health regulates the surface disposal of produced wastes from gas and oil wells. No pond is allowed to discharge to the surface (land or water). Construction requirements specify that pits must be protected from intrusion of surface water, must be constructed of impervious materials, and must be located at least 5 feet above ground water. Pits must be properly located above ordinary high-water marks for surface wastes. Pits may not be located within 200 feet of a fault or at the bottom of creeks, rivers, or natural drainages.*

Surface disposal into unlined ponds is allowed if the wastewater contains less than 5,000 mg/L total dissolved solids and if the wastewater does not contain "objectionable or toxic levels of any constituent as shown by chemical analyses." This requirement is waived for sites discharging less than 5 barrels of water per day. Small dischargers into unlined pits are required only to notify the Department of Health with minimal site information. Application for approval to

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*Onsite disposal facilities are presumed to include onsite evaporation pits. The Division of Oil, Gas, and Mining rules do not include specific guidance regarding onsite disposal facilities; however, their reserve pit guidance is probably applied to produced water pits as well. There appears to be some overlap in authority for onsite pits between the Utah Department of Health and the Division of Oil, Gas, and Mining.

discharge into unlined pits must include an estimate of waste volume, estimate of percolation and net evaporation rates, and information about freshwater aquifers within a 1-square-mile radius of the proposed site.

For disposal ponds without artificial liners that receive more than 100 barrels per day, the Department of Health requires a monitoring program including monitoring wells.

For artificially lined ponds, the Department of Health requires "an underlying gravel-filled sump and lateral system, or other suitable devices for detection of leaks." The Department of Health, Bureau of Water Pollution Control, is considering a requirement that all ponds (lined or unlined) be equipped with a leak detection system. In general, the Bureau feels that pit siting is more important than construction requirements. Any discharge of produced water onto roads is prohibited.

All injection wells must be operated to prevent damage to drinking water or other resources and to confine injected fluids to the approved interval. The application for an injection well must include information on all other wells within a half-mile area of the proposed injection well. It must also provide adequate evidence that the proposed injection pressures will not result in fracturing of the confining interval, which could enable injected or formation fluids to migrate out of that interval. Before injection begins, the operator must use a pressure test to test the casing. The test must be at 300 psi or the maximum authorized pressure (for a new well), whichever is greater, with a ceiling of 1,000 psi (for a converted well). Subsequent pressure tests must be administered every 5 years (except that, in lieu of pressure tests, the operator may monitor and report on the pressure in the casing-tubing annulus on a monthly basis, or use other test methods approved by the Division).

Plugging/Abandonment

No time limit is established for temporary abandonment of a well. A well is temporarily abandoned if operations have ceased, intervals open to the wellbore have been properly sealed with a cement plug or bridge plug, and there is no migration of fluids.

When plugging, cement plugs must be placed above each producing formation (100-foot length); from 50 feet below to 50 feet above the freshwater zone (or 100-foot plugs centered at the base and top of the zone); at the base of the surface casing (50-foot); and centered across the casing stub if any casing is cut and pulled (100-foot, along with a second plug the same length centered across the casing shoe of the next larger casing). At least 10 bags of cement should be placed at the surface, completely plugging the entire hole (including all annuli, if more than one string of casing remains at the surface). Perforated intervals must be plugged with cement. Intervals between plugs must be filled with a noncorrosive fluid of adequate density to prevent migration.

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VIRGINIA

INTRODUCTION

Virginia produced 26,654 barrels of oil from 41 producing oil wells and 15,041,438 MCF of gas from 495 gas wells in 1985.

REGULATORY AGENCY

One agency principally regulates oil and gas activities in Virginia:

- Virginia Department of Mines, Minerals, and Energy/Division of Mines - Oil and Gas Section.

The Oil and Gas Section is governed by the Virginia Oil and Gas Act and by the Rules and Regulations for Conservation of Oil and Gas Resources and Well Spacing. These Rules and Regulations were adopted by the Virginia Oil and Gas Conservation Commission, the Virginia Well Review Board, and the Chief of the Division of Mines and Quarries (DMQ) and were issued by the Virginia Department of Labor and Industry in 1983. In 1985, a reorganization of the State government created the Department of Mines, Minerals, and Energy (DMME). This resulted in the shift of DMQ, now referred to as the Division of Mines, from Labor and Industry to DMME. The Oil and Gas Section issues drilling permits and regulates the details of the industry through this process. The State does not have primacy for the UIC program Class II wells, but no underground injection of fluids is currently associated with the Virginia industry. There has been drilling on Federal lands, but such lands are owned by the National Forest Service, and the Service serves as another surface landowner in such drilling activity. The Service would manage its concerns principally through the surface lease process. The Virginia

Water Control Board would become involved only in the event of an incident that potentially could affect surface water quality.

STATE RULES AND REGULATIONS

Drilling

All disturbance to the land associated with the development of the drilling site, including the construction of pits and access roads, must comply with standards set down in the Virginia Soil and Erosion Control Handbook.

Pits associated with the drilling of a well must prevent water pollution. It is the policy of the Oil and Gas Section that drilling pits must be lined with a plastic liner. After drilling is complete, liquids in the pits may be treated, primarily to adjust pH, and land applied solids are buried in the pit. The drill site and any associated pits must be reclaimed within 1 year after drilling ceases.

In general, there is little fluid associated with the drilling process in Virginia. Such fluids as may be present are not high in chloride concentration. Generally, the fluid is tested by the driller, the pH is adjusted if necessary, and the water is sprayed on the surrounding land. Pit muds are buried onsite and the pit area is reclaimed.

Production

No pit may be used for the ultimate disposal of salt water (Part III, Regulation 3.09(e) for Conservation of Oil and Gas). Salt water must be periodically drained or removed, or properly disposed of from any pit in which it is retained.

Almost no fluid is associated with gas production in Virginia. Very small amounts of fluids are produced with the 100 gallons of oil produced per day statewide. As a result, produced wastes generally are held in steel tanks. Dikes are required around the tanks, and fluids generally are allowed to flow into the diked area, where they disappear through evaporation and infiltration.

Offsite Disposal

No use is made of offsite and commercial pits in Virginia.

Plugging/Abandonment

Under the Virginia Oil and Gas Act, operators are required to immediately plug a well "upon the abandonment or cessation of operation" of that well. Where there is good economic cause, however, gas wells may be capped for an indefinite period.

Different plugging requirements exist for wells, depending on whether they penetrate coal seams and, if they do, whether with or without coal protection string. Cement plugs are required 20 feet above each oil, gas, or water-bearing stratum and 10 feet below the bottom of the largest casing left in the well. Mud, clay, or another nonporous material is used to fill all spaces in the well not filled by plugs. Additional requirements are made for perforations that cannot be readily filled by the above methods and for the protection of coal seams.

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Personal Communications:

William Edwards, Department of Mines, Minerals and Energy (804) 257-0330.

James Henderson, State Oil and Gas Inspector (703) 628-8115.

WEST VIRGINIA

INTRODUCTION

West Virginia produces about 3.6 million barrels of oil and 7.5 BCF of gas per year from 15,895 wells. Gas production of 142.5 billion cubic feet annually is realized from 32,500 gas wells. Between 1,800 and 2,500 drilling permits are issued annually, although the number of wells drilled dropped in 1986.

REGULATORY AGENCIES

Two agencies now regulate oil and gas activities in West Virginia:

- West Virginia Department of Energy, Oil and Gas Division; and
- U.S. Bureau of Land Management.

The West Virginia Energy Act, passed on April 12, 1985, created the West Virginia Department of Energy and vested in the Department jurisdiction over oil and gas activities (as well as other energy-related activities) in the State. The Department has assumed the responsibilities previously carried out by the Department of Mines, Office of Oil and Gas, and is in the process of assuming relevant program responsibilities from the Department of Natural Resources, Water Resources Division. Among the programs that are to be transferred, after approval by EPA, are those aspects of the delegated NPDES, underground injection, and hazardous waste programs that bear on oil and gas exploration, development, and production. Pending re-delegation by EPA, the Department of Natural Resources is still the lead agency for these activities, and the Department of Natural Resources and the Department of Energy are cooperating on the environmental regulation and oversight of the oil and gas production industry.

Within the Department of Energy, the Division of Oil and Gas has responsibility for the regulation of the State's oil and gas industry. The Division has new regulations that have been approved by the State legislature. The regulations were scheduleed to go into effect about June 14, 1987. The regulatory requirements summarized below describe these rules.

The U.S. Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands. Their rules are discussed in a separate section on Federal agencies, Volume 1, Chapter VII. The U.S. Forest Service retains surface rights for Federal forests and grasslands. The Service coordinates surface stipulations with the Bureau of Land Management where applicable.

STATE RULES AND REGULATIONS

Drilling

Pit Construction/Management

Each pit used for drilling wastes is subject to the terms of a general West Virginia NPDES permit for construction, management, and discharge. The general permit was first established by the Division of Water Resources of the Department of Natural Resources on July 10, 1985. The requirements in the general permit are also found in the proposed Department of Energy regulations.

Pits must be constructed "to prevent seepage, leakage or overflows" and maintain integrity. If an operator is unable to maintain adequate freeboard to prevent overflows, an additional pit must be built. There is no liner requirement, but there is a stipulation that where the soil "is not suitable to prevent seepage or leakage, other materials which are impervious shall be used as a liner for a pit."

Unlined dikes must be free of large rocks, trees, or other growth that could damage the pit's integrity.

During operation of the pit, it is prohibited to dump into the pit production brine, unused fracturing fluid or acid, compressor oil, refuse, diesel, kerosene, halogenated phenol, or drilling additives prepared in diesel or kerosene.

Pit Closure

Pits are to be filled within 6 months after the cessation of drilling. The drill cuttings may be buried onsite, after disposal of liquids.

Disposal

Treated wastewaters generated during drilling, reworking, and treatment of wells may be discharged for land application onsite, subject to the following limitations:

pH	6.0 - 10.0
Total iron	6 mg/L
Chloride	25,000 mg/L
Free or floating oil	no visible sheen on land.

In addition, monitoring is required for TSS, dissolved oxygen, manganese, conductivity, settleable solids, and total organic carbon.

Required treatment includes pH adjustment, aeration, and extended settling for at least 10 days. Free or floating oil should be skimmed off and removed from the pit before treatment and, if observed, before discharge. Land application should not be carried out on saturated, frozen, impermeable, or unvegetated land, and must be at a rate that will not cause ponding or erosion. To prevent the discharge of sludge, there must be a discharge device on the pit that ensures that the discharge will be from near the surface of the pit water level.

Discharge onto property off the drilling site requires both a permit and the permission of the landowner.

Produced Waters

The Department of Energy regulations, beyond prohibiting the placement of produced salt water in drilling pits, specify that when such water is produced it must be "contained in sump pits no larger than necessary for the purpose." There is no general permit for land discharge of salt water, and discharge into waters of the State is prohibited. Salt water may be injected into Class II wells. (For figures on actual disposal patterns, see the section on current management practices, Volume 1, Chapter III.) There is no prohibition against use of brines on roads, although research is currently underway on this possibility.

Injection

Class II injection wells are permitted for both enhanced recovery (529 wells) and disposal (53 wells).

Injection should be through a tubing and packer arrangement, with the packer set immediately above the injection zone. The annulus must be monitored by a pressure-sensitive device. Injection pressure must be regulated to minimize the possibility of fracturing the confining strata. "Disposal into the same formation from which the water is produced is preferable."

Mechanical integrity tests for injection wells are made at one and one-half to two times the injection pressure for 20 minutes, with a 5 percent allowable variance.

Offsite Disposal

Wastes may be transported offsite to appropriate disposal facilities. If these facilities discharge wastes after treatment, they must be separately permitted.

Plugging/Abandonment

Wells completed as dry holes, or wells not in use for a period of 12 months, are presumed abandoned and must be "promptly" plugged, unless the operator can prove "bona fide future use."

Cement plugs (of unspecified length) shall be set 20 feet above each oil, gas, or water-bearing stratum (except that if such strata are not widely separated and are free from water, they may be treated as a single stratum). A final plug must be placed 10 feet below the bottom of the largest casing in the well. Mud, clay, or other nonporous material is to fill all space in the well from the bottom of the well (or from a permanent bridge anchored 30 feet below the lowest stratum) to the lowest plug, between each of the plugs, and from the highest plug to the surface. Unfillable cavities created when strata were perforated should be isolated by plugs placed 20 feet above and below the stratum, or a liner should be placed from at least 20 feet above to 20 feet below the stratum and filled with cement.

Special additional requirements (e.g., use of expanding rather than hydraulic cement, and more cement plugs) are imposed to protect workable coal beds.

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Personal Communications:

John Johnston, Oil and Gas Division, West Virginia Department of Energy (304) 348-3741.

Ron Shipley, West Virginia Department of Natural Resources (304) 348-2754.

Ted Streit, former head of Office of Oil and Gas, September 25, 1986.

WYOMING

INTRODUCTION

Wyoming produced 130,984,917 barrels of oil and 597,896,000 MCF of gas in 1985. Production is from 12,218 oil wells and 2,220 gas wells.

Fifty-two percent of the State's oil production is produced from the 20 largest fields. Twelve of those fields are 58 years old or older. Oil, water, and gas have always been produced from these areas. The produced water historically has been reinjected, evaporated in pits, or discharged into drainages.

REGULATORY AGENCIES

Three agencies regulate oil and gas activity in Wyoming:

- Wyoming Oil and Gas Conservation Commission;
- Wyoming Department of Environmental Quality; and
- U.S. Bureau of Land Management.

The Wyoming Oil and Gas Conservation Commission has general authority over all oil and gas production in Wyoming, and the specific responsibility to "monitor and regulate, by the promulgation of rules and the issuance of orders, the location, operation, and reclamation of produced water and emergency overflow pits associated with oil and gas production." The Commission regulates industry practices and procedures with regard to construction, location, and operation of drilling and production pits, both onsite and offsite. The Oil and Gas Conservation Commission is chaired by the Governor of Wyoming; four other commissioners serve with the Governor. The Office of the State Oil and Gas Supervisor is primarily responsible for regulation of industry practices.

Wyoming is an NPDES-delegated State. The Wyoming Department of Environmental Quality has NPDES authority for all discharges. DEQ also has responsibility for permitting the construction, maintenance, and operation of commercial pits. In addition, DEQ has authority for the land application of all types of exploration and production wastes.

The specific division of roles between the Wyoming Oil and Gas Conservation Commission and the Department of Environmental Quality was previously defined by a "Memorandum of Agreement" (MOA) of September 13, 1983; a memorandum from the Attorney General's office on January 18, 1982; and an MOA dated October 14, 1981.

However, the 1987 session of the Wyoming State Legislature passed a bill creating a new section in the Wyoming Oil and Gas Conservation Commission Act. The new legislation gives the Commission exclusive authority over all noncommercial oil field pits on a lease, unit, or communitized area (except for discharges from such pits subject to NPDES permitting). See §30-5-104(d)(VI)(A) and (B).

The Bureau of Land Management (BLM) has jurisdiction over drilling and production on Federal lands. For drilling on Federal land, BLM handles all Applications to Drill. BLM requires extensive environmental documentation, including environmental assessments, and develops environmental impact statements. For produced water, BLM routinely approves discharges of up to 5 barrels/day under NTL-2B. For further discussion of the rules and procedures of BLM, see the section on Federal regulations, Volume 1, Chapter VII.

STATE RULES AND REGULATIONS

Drilling

Pit Construction/Management

Earthen pits are required to be constructed to prevent pollution of streams or underground water, or unreasonable damage to the surface of leased premises or other lands. The rules do not require pit or pond liners, leak detection, or other modifications to a simple earthen pit except where "potential for communication between the pit contents and surface water or shallow ground water is high." Each pit application is reviewed before approval, taking into consideration a wide variety of factors including the soil type on which a proposed pit is to be constructed. Quality of the contained water, especially the TDS level, is also an important consideration. The State Supervisor makes this determination based on the information presented in the permit application form. Use of chemicals that destroy, remove, or reduce the fluid seal of a reserve pit is prohibited. Chemical or mechanical treatment of reserve pits may be specially allowed after a public hearing before the Oil and Gas Conservation Commission.

Workover and completion pits are exempted from permit requirements if their use is limited to containment of oil and/or water and they do not contain acids or other chemical fluids. There is no requirement in the regulations for segregation of drilling muds, produced waters, or other wastes associated with drilling or production. Practices tend to vary significantly with the operator.

Pit Closure

Reserve pits must be reclaimed within a year of last use, unless the Supervisor grants a variance. After evaporation, discharge, or hauling of the liquid material in the pit. the drill cuttings are buried onsite and the land is rehabilitated in accordance with the landowner's wishes. Bonds guaranteeing plugging of the well and pit reclamation are not released until the Commission has inspected and approved the reclaimed pit and drillsite.

Discharge

Drilling fluids from reserve pits may be evaporated, applied to road surfaces, applied to land other than road surfaces, or hauled to a central disposal facility.

Section 326 of the rules of the Oil and Gas Conservation Commission states: "A permit may be allowed by DEQ for one time land application of drilling fluids. At no time will drilling fluids be discharged into live waters or into any drainages that lead to live waters of the state." Section 11(a) of Chapter VII of the regulations of the Department of Environmental Quality (DEQ) establishes a no-discharge rule for "drilling muds and other liquids associated with the drilling of oil and/or gas wells." Section 11(b), however, allows exceptions where the operator has provided a complete analysis of the drilling liquid, the volume and location of discharge, and the name of the receiving water; DEQ has determined that the discharge would not cause significant environmental damage or contamination of public water supplies; and the landowner has agreed.

During the period 1983 to 1985, DEQ approved 21 permits for application of drilling fluids to roads. The State currently lacks specific road permit standards or numeric criteria. Information is required on pH, conductivity, and TDS contents of the wastes. Actual concentrations of TDS in permits approved for road application of drilling fluids during the above period varied from a few hundred to 10,900 mg/L. A DEQ memorandum notes several criteria established in such permits. Those that apply to drilling fluids include: limitation of application rates to those specified in the permit; application to avoid runoff or ponding; no application on slopes exceeding 8 percent, within 300 feet of definable high water marks of drainages, irrigation canals, lakes or reservoirs, or when the soil is saturated; and landowner approval.

During the same 1983 to 1985 period, DEQ issued 16 permits for drilling fluids to be applied to land other than roads. Such permits require that the fluids meet the criteria established in Chapter XI, Section 55(c)(ii), Part E for irrigation water quality, including:

Total dissolved solids	2,100 mg/L
Chlorides	1,500 mg/L
Oil and grease	20,000 lb/acre, when soil incorporated (surface 6 inches); 2,000 lb/acre when surface applied
Sulfates	960 mg/L
Boron	2 mg/L
Arsenic	0.1 mg/L
Chromium	1 mg/L
Selenium	0.2 mg/L
Nickel	0.2 mg/L
Zinc	2 mg/L
Copper	1 mg/L
Bicarbonates	<50% of total anion concentration mq/L
pH	4.5 - 9.0.

Produced Waters

Produced waters are disposed of through injection for enhanced recovery (approximately 63 percent), surface water discharge (approximately 30 percent), injection into disposal wells, discharge into centralized disposal pits, discharge into commercial disposal pits, or road application.

Disposal/Storage Pits

The Oil and Gas Conservation Commission has jurisdiction over the permitting, construction, and management of all produced water pits on private and State lands. The Commission requires permits for pits receiving more than 5 barrels of produced water per day. However, such permits include requirements for liners only in special cases where "potential for communication between the pit contents and surface water or shallow ground water is high." The Commission may administratively approve field-wide or area-wide applications covering earthen retaining pit construction and operation.

Pits must be kept reasonably clear of surface accumulations of oil or other liquid hydrocarbons, and the accumulations must be cleared within 10 days when discovered. Pits must be fenced when near human habitation or sensitive areas for wildlife or domestic stock and must be flagged as required.

Surface Discharge

The Wyoming Department of Environmental Quality's Water Quality Rules and Regulations, Chapter VII, describe the rules for discharges of produced water that could enter surface waters, as permitted by EPA's Agricultural and Wildlife Water Use Subcategory. Discharge of produced water may be permitted if the following effluent limitations are met:

Chlorides	2,000 mg/L
Sulfates	3,000 mg/L
Total dissolved solids	5,000 mg/L
pH	6.5 8.5
Oil and grease	10 mg/L.

There is also a general prohibition on discharges containing toxic substances in concentrations or combinations toxic to human, animal, or aquatic life.

Exceptions may be granted to the above limitations if a landowner submits a "letter of beneficial use" specifically requesting that the discharge in question be allowed to continue and indicating the specific beneficial use and its history, or if the Wyoming Fish and Game Department indicates the discharge is of value to fish or wildlife. This exemption does not apply if the produced waters would be discharged to the waters of the United States or if the discharge would lead to a violation of Wyoming's water quality standards.

During 1983 to 1985, five permits were issued by DEQ for road application of produced waters. In addition to the road application restrictions that apply to drilling fluids, produced water must have a TDS concentration of greater than 5,000 mg/L and less than 50,000 mg/L.

Injection

The Wyoming Oil and Gas Conservation Commission has delegated responsibility for the UIC Class II program and issues permits for both enhanced recovery (4,548 wells) and noncommercial disposal (196 wells). Disposal wells permitted by the Commission meet the permitting requirements of Chapter IX, Wyoming Water Quality Rules and Regulations. For both types of well, the applicant has the burden of demonstrating at a public hearing that the injection or disposal zone is not a source of drinking water and by certain criteria can be exempt from protection as fresh and potable water. The applicant must also supply an application for approval of use of the well for injection, which includes the following points:

1. Proof that the well is cased and cemented in such a way that fluids are prevented from entering any zone but that exempt;
2. Evidence and data to demonstrate that operation of the well at the proposed maximum injection pressure with proposed volumes will not initiate fractures through the confining zone;
3. A statement detailing procedures for pressure testing the casing in the well prior to any use;
4. A plat showing the location of all wells within a one-quarter mile radius of the proposed injection or disposal well and a statement relative to the mechanical condition or abandonment of each;
5. An affidavit showing that all surface owners and owners of interest within a one-half mile radius of the well have been provided notice of the proposal; and
6. A geologic description of the reservoir that will receive the fluids, which includes its areal extent.

The surface casing must be run to reach a depth below all known or reasonably estimated utilizable domestic freshwater levels. The surface casing should be cemented with sufficient cement to fill the annulus to the top of the hole.

Before beginning injection, and at least once every subsequent 5-year period, the operator must test the well's mechanical integrity. In a new well, the casing outside the tubing must be tested at a pressure not less than the maximum authorized injection pressure, or at 300 psi, whichever is greater. In a converted well, the test must be at the lesser of 1,000 psi or the maximum authorized injection pressure, but no less than

300 psi. A retrievable bridge plug or approved logging technique will be used in casing to test tubingless completions.

Offsite Disposal

The Department of Environmental Quality permits the construction of commercial pits. Chapter III of the Wyoming Water Quality Rules and Regulations establishes permit processing and application requirements. Minimum standards for pits and wells are established in Chapter XI. The operator must demonstrate that the facility will not allow a discharge to ground water by direct or indirect discharge, percolation, or filtration; that the quality of the wastewater will not cause a violation of ground-water standards; or that existing soils or geology will not allow a discharge to ground water. If the applicant cannot demonstrate any of these alternatives, the operator may conduct a subsurface investigation and develop a design to prevent violation of ground-water standards. These designs may consist of leachate collection systems, barriers with a pumpback system, attenuation, or aquifer cleanup after completion of the operation. DEQ may require a monitoring program for such facilities.

At the present time, 11 facilities are authorized to receive drilling fluids and produced water, and an additional 11 are authorized to receive produced water only.

Plugging/Abandonment

A well may be temporarily abandoned so long as the hole is cased or left in such a manner as to prevent migration of oil, gas, water, or other substances from the formations or horizons of origin. Monthly reports must be submitted to the Commission, and bonding requirements are kept in force until the well is permanently abandoned. There are no restrictions on the time period for which the well may retain such status; however, specific approval must be obtained from the Wyoming Oil and Gas Conservation Commission if a well is temporarily abandoned for more than 1 year. Temporarily abandoned injection wells must meet the 5-year testing requirements of the UIC program.

When wells are plugged, cement plugs of at least 100 feet must be placed over open hole porous and permeable formations (or every 2,500 feet in lieu of such formations), over the stub of the casing left in the wellbore, and in the base of the surface casing. Cast iron bridge plugs set in the casing will be capped with at least two sacks of cement. Open perforations must be squeeze-cemented.

References

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Personal Communications:

E. J. Fanning, Department of Environmental Quality, Water Quality Division, August 11 and August 14, 1986, and March 6, 1987. (307) 777-7781.

Janie Nelson, Wyoming Oil and Gas Conservation Commission, August 14, 1986. (307) 234-7147.

APPENDIX B

GLOSSARY OF TERMS
FOR VOLUME 1

Abandon: To cease producing oil or gas from a well when it becomes unprofitable. A wildcat may be abandoned after it has been proven nonproductive. Usually, before a well is abandoned, some of the casing is removed and salvaged and one or more cement plugs are placed in the borehole to prevent migration of fluids between the various formations. In many States, abandonment must be approved by an official regulatory agency before being undertaken.

Acid: Any chemical compound, one element of which is hydrogen, that dissociates in solution to produce free-hydrogen ions. For example, hydrochloric acid, HCl, dissociates in water to produce hydrogen ions, H^+, and chloride ions, Cl^-.

Acidize: To treat oil-bearing limestone or other formations, using a chemical reaction with acid, to increase production. Hydrochloric or other acid is injected into the formation under pressure. The acid etches the rock, enlarging the pore spaces and passages through which the reservoir fluids flow. The acid is then pumped out and the well is swabbed and put back into production. Chemical inhibitors combined with the acid prevent corrosion of the pipe.

Additive: A substance or compound added in small amounts to a larger volume of another substance to change some characteristic of the latter In the oil industry, additives are used in lubricating oil, fuel, drilling mud, and cement for cementing casing.

Adsorption: The adhesion of a thin film of a gas or liquid to the surface of a solid. Liquid hydrocarbons are recovered from natural gas by passing the gas through activated charcoal, which extracts the heavier hydrocarbons. Steam treatment of the charcoal removes the adsorbed hydrocarbons, which are then collected and recondensed.

Aeration: The technique of injecting air or other gas into a fluid. For example, air is injected into drilling fluid to reduce the density of the fluid.

Air Drilling: A method of rotary drilling that uses compressed air as its circulation medium. This method of removing cuttings from the wellbore is as efficient or more efficient than the traditional methods using water or drilling mud; in addition, the rate of penetration is increased considerably when air drilling is used. However, a principal problem in air drilling is the penetration of formations containing water, since the entry of water into the system reduces its efficiency.

Alkalinity: The combining power of a base, or alkali, as measured by the number of equivalents of an acid with which it reacts to form a salt.

Annular Injection: Long-term disposal of wastes between the outer wall of the drill stem or tubing and the inner wall of the casing or open hole.

Annulus or Annular Space: the space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

API: The American Petroleum Institute. Founded in 1920, this national oil trade organization is the leading standardizing organization on oil-field drilling and producing equipment. It maintains departments of transportation, refining, and marketing in Washington, D.C., and a department of production in Dallas.

Artificial Lift: Any method used to raise oil to the surface through a well after reservoir pressure has declined to the point at which the well no longer produces by means of natural energy. Artificial lift may also be used during primary recovery if the initial reservoir pressure is inadequate to bring the hydrocarbons to the surface. Sucker-rod pumps, hydraulic pumps, submersible pumps, and gas lift are the most common methods of artificial lift.

Attapulgite: A fibrous clay mineral that is a viscosity-building substance, used principally in saltwater-based drilling muds.

Bactericide: Anything that destroys bacteria.

Barite: Barium sulfate, $BaSO_4$; a mineral used to increase the weight of drilling mud. Its specific gravity is 4.2.

Barrel (bbl): A measure of volume for petroleum products. One barrel (1 bbl) is equivalent to 42 U.S. gallons or 158.97 liters. One cubic meter (1 m^3) equals 6.2897 bbl.

Basin: A synclinal structure in the subsurface, formerly the bed of an ancient sea. Because it is composed of sedimentary rock and its contours provide traps for petroleum, a basin is a good prospect for exploration. For example, the Permian Basin in West Texas is a major oil producer.

Basic Sediment and Water (BS&W): The water and other extraneous material present in crude oil. Usually, the BS&W content must be quite low before a pipeline will accept the oil for delivery to a refinery. The amount acceptable depends on a number of factors but usually runs from less than 5 percent to a small fraction of 1 percent.

Bentonite: A colloidal clay, composed of montmorillonite, which swells when wet. Because of its gel-forming properties, bentonite is a major component of drilling muds.

Bit: The cutting or boring element used in drilling oil and gas wells. Most bits used in rotary drilling are roller-cone bits. The bit consists of the cutting element and the circulating element. The circulating element permits the passage of drilling fluid and utilizes the hydraulic force of the fluid stream to improve drilling rates. In rotary drilling, several drill collars are joined to the bottom end of the drill-pipe column. The bit is attached to the end of the drill collar.

Blowdown: The emptying or depressurizing of a material from a vessel. The material thus discarded.

Blowout Preventer (BOP): Equipment installed at the wellhead at surface level on land rigs and on the seafloor of floating offshore rigs to prevent the escape of pressure either in the annular space between the casing and drill pipe or in an open hole during drilling and completion operations.

Blow Out: To suddenly expel oil-well fluids from the borehole with great velocity. To expel a portion of water and steam from a boiler to limit its concentration of minerals.

Borehole: The wellbore; the hole made by drilling or boring.

Brackish Water: Water that contains relatively low concentrations of any soluble salts. Brackish water is saltier than fresh water but not as salty as salt water.

Brine: Water that has a large quantity of salt, especially sodium chloride, dissolved in it; salt water.

Burn Pit: An earthen pit in which waste oil and other materials are burned.

Cable Tool Drilling: A drilling method in which the hole is drilled by dropping a sharply pointed bit on the bottom of the hole. The bit is attached to a cable and the cable is picked up and dropped, picked up and dropped, over and over, as the hole is drilled.

Casing: Steel pipe placed in an oil or gas well as drilling progresses to prevent the wall of the well from caving in during drilling and to provide a means of extracting petroleum if the well is productive.

Casinghead Gas: Gas produced with oil.

Casing String: Casing is manufactured in lengths of about 30 ft, each length or joint being joined to another as casing is run in a well. The entire length of all the joints of casing is called the casing string.

Cement: A powder consisting of alumina, silica, lime, and other substances which hardens when mixed with water. Extensively used in the oil industry to bond casing to the walls of the wellbore.

Cement Additive: A material added to cement during cementing of a well to change its properties. Chemical accelerators, chemical retarders, and weight-reduction materials are common additives.

Cement Bond: The adherence of casing to cement and cement to formation. When casing is run in a well, it is set, or bonded, to the formation by means of cement.

Cement Plug: A portion of cement placed at some point in the wellbore to seal it.

Centralized Brine Disposal Pit: An excavated or above-grade earthen impoundment located away from the oil or gas operations from which it receives produced fluids (brine). Centralized pits usually receive fluids from many wells, leases, or fields.

Centralized Combined Mud/Brine Disposal Pit: An excavated or above-grade earthen impoundment located away from the oil or gas operations from which it receives produced fluids (brine) and drilling fluids. Centralized pits usually receive fluids from many wells, leases, or fields.

Centralized Mud Disposal Pit: An excavated or above-grade earthen impoundment located away from the drilling operations from which it receives drilling muds. Centralized pits usually receive fluids from many drilling sites.

Centralized Treatment Facility (Mud or Brine): Any facility accepting drilling fluids or produced fluids for processing. This definition encompasses municipal treatment plants, private treatment facilities, or publicly owned treatment works for treatment of drilling fluids or produced fluids. These facilities usually accept a spectrum of wastes from a number of oil, gas, or geothermal sites, or in combination with wastes from other sources.

Centrifuge: A device for the mechanical separation of solids from a liquid. Usually used on weighted muds to recover the mud and discard solids. The centrifuge uses high-speed mechanical rotation to achieve this separation as distinguished from the cyclone-type separator in which the fluid energy alone provides the separating force.

Christmas Tree: Assembly of fittings and valves at the tip of the casing of an oil well that controls the flow of oil from the well.

Circulate: To pass from one point throughout a system and back to the starting point. Drilling fluid circulates from the suction pit through the drill pipe to the bottom of the well and returns through the annulus.

Clean Water Act: The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 et seq.), as amended by the Clean Water Act of 1977 (P. L. 95-217).

Close-in: A well capable of producing oil or gas, but temporarily not producing.

Collar: A coupling device used to join two lengths of pipe. A combination collar has left-hand threads in one end and right-hand threads in the other. A drill collar.

Commercial Production: Oil and gas output of sufficient quantity to justify keeping a well in production.

Completion Fluid: A special drilling mud used when a well is being completed. It is selected not only for its ability to control formation pressure, but also for its properties that minimize formation damage.

Completion Operations: Work performed in an oil or gas well after the well has been drilled to the point at which the production string of casing is to be set. This work includes setting the casing, perforating, artificial stimulation, production testing, and equipping the well for production, all prior to the commencement of the actual production of oil or gas in paying quantities, or in the case of an injection or service well, prior to when the well is plugged and abandoned.

Condensate: A light hydrocarbon liquid obtained by condensation of hydrocarbon vapors. It consists of varying proportions of butane, propane, pentane, and heavier fractions, with little or no ethane or methane.

Conductor Pipe: A short string of large-diameter casing used offshore and in marshy locations to keep the top of the wellbore open and to provide a means of conveying the upflowing drilling fluid from the wellbore to the mud pit.

Coning: The encroachment of reservoir water into the oil column and well because of uncontrolled production.

Conductivity: The ability to transmit or convey (as heat or electricity).

Connate Water: The original water retained in the pore spaces, or interstices, of a formation from the time the formation was created.

Cooling Tower: A structure in which air contact is used to cool a stream of water that has been heated by circulating through a system. The air flows counter- or cross-currently to the water.

Corrosion: A complex chemical or electrochemical process by which metal is destroyed through reaction with its environment. For example, rust is corrosion.

Crude Oil: Unrefined liquid petroleum. It ranges in gravity from 9^{o} to 55^{o} API and in color from yellow to black, and it may have a paraffin, asphalt, or mixed base. If a crude oil, or crude, contains a sizable amount of sulfur or sulfur compounds, it is called a sour crude; if it has little or no sulfur, it is called a sweet crude. In addition, crude oils may be referred to as heavy or light according to API gravity, the lighter oils having the higher gravities.

Cuttings: The fragments of rock dislodged by the bit and brought to the surface in the drilling mud. Washed and dried samples of the cuttings are analyzed by geologists to obtain information about the formations drilled.

Deflocculation: The dispersion of solids that have stuck together in drilling fluid, usually by means of chemical thinners.

Defoamer: Any chemical that prevents or lessens frothing or foaming in another agent.

Dehydrate: To remove water from a substance. Dehydration of crude oil is normally accomplished by emulsion treating with emulsion breakers. The water vapor in natural gas must be removed to meet pipeline requirements; a typical maximum allowable water vapor content is 7 lb per MMcf.

Demulsify: To resolve an emulsion, especially of water and oil, into its components.

Desander: A centrifugal device used to remove fine particles of sand from drilling fluid to prevent abrasion of the pumps. A desander usually operates on the principle of a fast-moving stream of fluid being put into a whirling motion inside a cone-shaped vessel.

Desiccant: A substance able to remove water from another substance with which it is in contact. It may be liquid (as triethylene glycol) or solid (as silica gel).

Desilter: A centrifugal device, similar to a desander, used to remove very fine particles, or silt, from drilling fluid to keep the amount of solids in the fluid to the lowest possible level. The lower the solids content of the mud is, the faster the rate of penetration.

Development Well: A well drilled in proven territory in a field to complete a pattern of production.

Discovery Well: The first oil or gas well drilled in a new field; the well that reveals the presence of a petroleum-bearing reservoir. Subsequent wells are development wells.

Disposal Well: A well into which salt water is pumped; usually part of a saltwater-disposal system.

Dope: A lubricant for the threads of oil field tubular goods.

Drill: To bore a hole in the earth, usually to find and remove subsurface formation fluids such as oil and gas.

Drill Collar: A heavy, thick-walled tube, usually steel, used between the drill pipe and the bit in the drill stem to weight the bit in order to improve its performance.

Drilling Fluid: The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspended medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase. Drilling fluids are circulated down the drill pipe and back up the hole between the drill pipe and the walls of the hole, usually to a surface pit. Drilling fluids are used to lubricate the drill bit, to lift cuttings, to seal off porous zones, and to prevent blowouts. There are two basic drilling media: muds (liquid) and gases. Each medium comprises a number of general types. The type of drilling fluid may be further broken down into numerous specific formulations.

Drill Pipe: The heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Joints of pipe 30 ft long are coupled together by means of tool joints.

Drill Site: The location of a drilling rig.

Drill Stem: The entire length of tubular pipes, composed of the kelly, the drill pipe, and drill collars, that make up the drilling assembly from the surface to the bottom of the hole.

Drill String: The column, or string, of drill pipe, not including the drill collars or kelly. Often, however, the term is loosely applied to include both the drill pipe and drill collars.

Drum: A cylindrical steel container with a capacity of 50 to 55 U.S. gal (200 liters) used to ship refined products.

Dry Hole: Any well that does not produce oil or gas in commercial quantities. A dry hole may flow water, gas, or even oil, but not enough to justify production.

Emulsion: A mixture in which one liquid, termed the dispersed phase, is uniformly distributed (usually as minute globules) in another liquid, called the continuous phase or dispersion medium. In an oil-water emulsion, the oil is the dispersed phase and the water the dispersion medium; in a water-oil emulsion the reverse holds. A typical product of oil wells, water-oil emulsion also is used as a drilling fluid.

Emulsion Breaker: A system, device, or process used for breaking down an emulsion and rendering it into two or more easily separated compounds (as water and oil). Emulsion breakers may be (1) devices to heat the emulsion, thus achieving separation by lowering the viscosity of the emulsion and allowing the water to settle out; (2) chemical compounds, which destroy or weaken the film around each globule of water, thus uniting all the drops; (3) mechanical devices such as settling tanks and wash tanks; or (4) electrostatic treaters, which use an electric field to cause coalescence of the water globules. This is also called electric dehydration.

Enhanced Oil Recovery (EOR): A method or methods applied to depleted reservoirs to make them productive once again. After an oil well has reached depletion, a certain amount of oil remains in the reservoir, which enhanced recovery is targeted to produce. EOR can encompass secondary and tertiary production.

EPA: United States Environmental Protection Agency.

Exploration: The search for reservoirs of oil and gas, including aerial and geophysical surveys, geological studies, core testing, and the drilling of wildcats.

Field: A geographical area in which a number of oil or gas wells produce from a continuous reservoir. A field may refer to surface area only or to underground productive formations as well. In a single field, there may be several separate reservoirs at varying depths.

Flocculation: A property of contaminants or special additives to a drilling fluid that causes the solids to coagulate.

Flowing Well: A well that produces oil or gas without any means of artificial lift.

Foaming Agent: A chemical used to lighten the water column in gas wells, in oil wells producing gas, and in drilling wells in which air or gas is used as the drilling fluid so that the water can be forced out with the air or gas to prevent its impeding the production or drilling rate.

Formation: A bed or deposit composed throughout of substantially the same kinds of rock; a lithologic unit. Each different formation is given a name, frequently as a result of the study of the formation outcrop at the surface and sometimes based on fossils found in the formation.

Formation Pressure: The pressure exerted by fluids in a formation, recorded in the hole at the level of the formation with the well shut in. It is also called reservoir pressure or shut-in bottomhole pressure.

Formation Water: The water originally in place in a formation.

Fracturing: A method of stimulating production by increasing the permeability of the producing formation. Under extremely high hydraulic pressure, a fluid is pumped downward through tubing or drill pipe and forced into the perforations in the casing. The fluid enters the formation and parts or fractures it. Sand grains, aluminum pellets, glass beads, or similar materials are carried in suspension by the fluid into the fractures. These are called propping agents. When the pressure is released at the surface, the fracturing fluid returns to the well, and the fractures partially close on the propping agents, leaving channels through which oil flows to the well.

Free Water: The water produced with oil. It usually settles out within 5 minutes when the well fluids become stationary in a settling space within a vessel.

Gas Lift: The process of raising or lifting fluid from a well by injecting gas down the well through tubing or through the tubing-casing annulus. Injected gas aerates the fluid to make it exert less pressure than the formation does; consequently, the higher formation pressure forces the fluid out of the wellbore. Gas may be injected continuously or intermittently, depending on the producing characteristics of the well and the arrangement of the gas-lift equipment.

Gas-Oil Ratio: Number of cubic feet of gas produced with a barrel of oil.

Gas Plant: An installation in which natural gas is processed to prepare it for sale to consumers. A gas plant separates desirable hydrocarbon components from the impurities in natural gas.

Gathering Line: A pipeline, usually of small diameter, used in gathering crude oil from the oil field to a point on a main pipeline.

Gel: A semisolid, jellylike state assumed by some collodial dispersions at rest. When agitated, the gel converts to a fluid state.

Glycol Dehydrator: A processing unit used to remove all or most of the water from gas. Usually a glycol unit includes a tower, in which the wet gas is put into contact with glycol to remove the water, and a reboiler, which heats the wet glycol to remove the water from it so the glycol can be recycled.

Hard Water: Water that contains dissolved compounds of calcium, magnesium, or both.

Heater-treater: A vessel that heats an emulsion and removes water and gas from the oil to raise it to a quality acceptable for pipeline transmission. A heater-treater is a combination of a heater, free-water knockout, and oil and gas separator.

Hydraulic Fracturing: The forcing into a formation of liquids under high pressure to open passages for oil and gas to flow through and into the wellbore.

Hydrocarbons: Organic compounds of hydrogen and carbon, whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solid.

Hydrostatic Head: The pressure exerted by a body of water at rest. The hydrostatic head of fresh water is 0.433 per foot of height. The hydrostatic heads of other liquids may be determined by comparing their gravities with the gravity of water.

Inhibitor: An additive used to retard undesirable chemical action in a product; added in small quantity to gasolines to prevent oxidation and gum formation, to lubricating oils to stop color change, and to corrosive environments to decrease corrosive action.

Injection Well: A well in which fluids have been injected into an underground stratum to increase reservoir pressure.

Intermediate Casing String: The string of casing set in a well after the surface casing to keep the hole from caving in. Sometimes the blowout preventers can be attached to it. The string is sometimes called protection casing.

Interstice: A pore space in a reservoir rock.

Joint: A single length (30 ft) of drill pipe or of drill collar, casing, tubing, or rod that has threaded connections at both ends. Several joints screwed together constitute a stand of pipe.

Kelly: The heavy settle member, four- or six-sided, suspended from the swivel through the rotary table and connected to the topmost joint of drill pipe to turn the drill stem as the rotary table turns. It has a bored passageway that permits fluid to be circulated into the drill stem and up the annulus, or vice versa.

Lease: A legal document executed between a landower, or a lessor, and a company or individual, as lessee, that grants the right to exploit the premises for minerals or other products. The area where production wells, stock tanks, separators, and production equipment are located.

Location (Drill Site): Place at which a well is to be or has been drilled.

Log: A systematic recording of data, as from the driller's log, mud log, electrical well log, or radioactivity log. Many different logs are run in wells being produced or drilled to obtain information about various characteristics of downhole formations.

Log a well: To run any of the various logs used to ascertain downhole information about a well.

Manifold: An accessory system of piping to a main piping system (or another conductor) that serves to divide a flow into several parts, to combine several flows into one, or to reroute a flow to any one of several possible destinations.

Marginal Well: An oil or gas well that produces such a small volume of hydrocarbons that the gross income therefrom provides only a small margin of profit or, in many cases, does not even cover the cost of production.

Mud: The liquid circulated through the wellbore during rotary drilling and workover operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formation. Although it originally was a suspension of earth solids (especially clays) in water, the mud used in modern drilling operations is a more complex, three-phase mixture of liquids, reactive solids, and inert solids. The liquid phase may be fresh water, diesel oil, or crude oil and may contain one or more conditioners.

Mud Pit: A reservoir or tank, usually made of steel plates, through which the drilling mud is cycled to allow sand and fine sediments to settle out. Additives are mixed with mud in the pit, and the fluid is temporarily stored there before being pumped back into the well. Mud pits are also called shaker pits, settling pits, and suction pits, depending on their main purpose.

NPDES Permit: A National Pollutant Discharge Elimination System permit issued under Section 402 of the Clean Water Act.

96-hr LC-50: The concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay after 96 hours of constant exposure.

Oil and Gas Separator: An item of production equipment used to separate the liquid components of the well stream from the gaseous elements. Separators are vertical or horizontal and are cylindrical or spherical in shape. Separation is accomplished principally by gravity, the heavier liquids falling to the bottom and the gas rising to the top. A float valve or other liquid-level control regulates the level of oil in the bottom of the separator.

Oil-based Mud: An oil mud that contains from less than 2 percent up to 5 percent water. The water is spread out, or dispersed, in the oil as small droplets.

Oil Field: The surface area overlying an oil reservoir or reservoirs. Commonly, the term includes not only the surface area but also the reservoir, wells, and production equipment.

Operator: The person or company, either proprietor or lessee, actually operating an oil well or lease.

Packer: A piece of downhole equipment, consisting of a sealing device, a holding or setting device, and an inside passage for fluids, used to block the flow of fluids through the annular space between the tubing and the wall of the wellbore by sealing off the space. It is usually made up in the tubing string some distance above the producing zone. A sealing element expands to prevent fluid flow except through the inside bore of the packer and into the tubing. Packers are classified according to configuration, use, and method of setting and whether or not they are retrievable (i.e., whether they can be removed when necessary, or whether they must be milled or drilled out and thus destroyed).

Packer Fluid: A liquid, usually mud but sometimes salt water or oil, used in a well when a packer is between the tubing and casing. Packer fluid must be heavy enough to shut off the pressure of the formation being produced, must not stiffen or settle out of suspension over long periods of time, and must be noncorrosive.

Perforate: To pierce the casing wall and cement to provide holes through which formation fluids may enter or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the borehole. Perforating is accomplished by lowering into the well a perforating gun, or perforator, that fires electrically detonated bullets or shaped charges from the surface.

Permeability: A measure of the ease with which fluids can flow through a porous rock.

Pig: A scraping tool that is forced through a pipeline or flow line to clean out accumulations of wax, scale, and so forth, from the inside walls of a pipe. A cleaning pig travels with the flow of product in the line, cleaning the walls of the pipe with blades or brushes. A batching pig is a cylinder with neoprene or plastic cups on either end used to separate different products traveling in the same pipeline.

Plug and Abandon (P&A): To place a cement plug into a dry hole and abandon it.

Porosity: The quality or state of possessing pores (as a rock formation). The ratio of the volume of interstices of a substance to the volume of its mass.

Primary Recovery: Oil production in which only existing natural energy sources in the reservoir provide for movement of the well fluids to the wellbore.

Produced Water: The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas. It can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Producing Zone: The zone or formation from which oil or gas is produced.

Production: The phase of the petroleum industry that deals with bringing the well fluids to the surface and separating them and with storing, gauging, and otherwise preparing the product for the pipeline.

Production Casing: The last string of casing or liner that is set in a well, inside of which is usually suspended the tubing string.

Propping Agent: A granular substance (as sand grains, walnut shells, or other material) carried in suspension by the fracturing fluid that serves to keep the cracks open when the fracturing fluid is withdrawn after a fracture treatment.

Radioactive Tracer: A radioactive material (often carnotite) put into a well to allow observation of fluid or gas movements by means of a tracer survey.

RCRA: The Resource Conservation and Recovery Act of 1976, as amended.

Reservoir: A subsurface, porous, permeable rock body in which oil or gas or both are stored. Most reservoir rocks are limestones, dolomites, sandstones, or a combination of these. The three basic types of hydrocarbon reservoirs are oil, gas, and condensate. An oil reservoir generally contains three fluids--gas, oil, and water--with oil the dominant product. In the typical oil reservoir, these fluids occur in different phases because of the variance in their gravities. Gas, the lightest, occupies the upper part of the reservoir rocks; water, the lower part; and oil, the intermediate section. In addition to occurring as a cap or in solution, gas may accumulate independently of the oil; if so, the reservoir is called a gas reservoir. Associated with the gas, in most instances, are salt water and some oil. In a condensate reservoir, the hydrocarbons may exist as a gas, but when brought to the surface, some of the heavier ones condense to a liquid or condensate. At the surface the hydrocarbons from a condensate reservoir consist of gas and a high-gravity crude (i.e., the condensate). Condensate wells are sometimes called gas-condensate reservoirs.

Resistivity: The electrical resistance offered to the passage of current; the opposite of conductivity.

Rig: The derrick, drawworks, and attendant surface equipment of a drilling or workover unit.

Rotary: The machine used to impart rotational power to the drill stem while permitting vertical movement of the pipe for rotary drilling. Modern rotary machines have a special component, the rotary bushing, to turn the kelly bushing, which permits vertical movement of the kelly while the stem is turning.

Secondary Recovery: Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from extraneous sources) into the wellbore. This injection effects a restoration of reservoir energy, which moves the formerly unrecoverable secondary reserves through the reservoir to the wellbore.

Sediment: The matter that settles to the bottom of a liquid; also called tank bottoms, basic sediment, and so forth.

Separator: A cylindrical or spherical vessel used to isolate the components in mixed streams of fluids.

Shale Shaker: A series of trays with sieves that vibrate to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the sieve is carefully selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. It is also called a shaker.

Sour: Containing hydrogen sulfide or caused by hydrogen sulfide or another sulfur compound.

Specific Gravity: The ratio of the weight of a substance at a given temperature to the weight of an equal volume of a standard substance at the same temperature. For example, if 1 $in.^3$ of water at 39°F weighs 1 unit and 1 $in.^3$ of another solid or liquid at 39°F weighs 0.95 unit, then the specific gravity of the substance is 0.95. In determining the specific gravity of gases, the comparison is made with the standard of air or hydrogen.

Spud: To move the drill stem up and down in the hole over a short distance without rotation. Careless execution of this operation creates pressure surges that can cause a formation to break down, which results in lost circulation.

Spud In: To begin drilling; to start the hole.

Stock Tank: A crude oil storage tank.

Stripper: A well nearing depletion that produces a very small amount of oil or gas.

Sump: A low place in a vessel or tank used to accumulate settlings that are later removed through an opening in the bottom of the vessel.

Supernatant: A liquid or fluid forming a layer above settled solids.

Surface Pipe: The first string of casing set in a well after the conductor pipe, varying in length from a few hundred feet to several thousand.

Surfactant: A substance that affects the properties of the surface of a liquid or solid by concentrating on the surface layer. The use of surfactants can ensure that the surface of one substance or object is in thorough contact with the surface of another substance.

Tank Battery: A group of production tanks located in the field that store crude oil.

Tertiary Recovery: A recovery method used to remove additional hydrocarbons after secondary recovery methods have been applied to a reservoir. Sometimes more hydrocarbons can be removed by injecting liquids or gases (usually different from those used in secondary recovery and applied with different techniques) into the reservoir.

Tubing: Small-diameter pipe that is run into a well to serve as a conduit for the passage of oil and gas to the surface.

Viscosity: A measure of the resistance of a liquid to flow. Resistance is brought about by the internal friction resulting from the combined effects of cohesion and adhesion. The viscosity of petroleum products is commonly expressed in terms of the time required for a specific volume of the liquid to flow through an orifice of a specific size.

Volatile: Readily vaporized.

Waterflood: A method of secondary recovery in which water is injected into a reservoir to remove additional quantities of oil that have been left behind after primary recovery. Usually, a waterflood involves the injection of water through wells specially set up for water injection and the removal of the water and oil from the wells drilled adjacent to the injection wells.

Weighting Material: A material with a specific gravity greater than that of cement; used to increase the density of drilling fluids or cement slurries.

Wellbore: A borehole; the hole drilled by the bit. A wellbore may have casing in it or may be open (i.e., uncased); or a portion of it may be cased and a portion of it may be open.

Well Completion: The activities and methods necessary to prepare a well for the production of oil and gas; the method by which a flow line for hydrocarbons is established between the reservoir and the surface. The method of well completion used by the operator depends on the individual characteristics of the producing formation or formations. These techniques include open-hole completions, conventional perforated completions, sand-exclusion completions, tubingless completions, multiple completions, and miniaturized completions.

Wellhead: The equipment used to maintain surface control of a well, including the casinghead, tubing head, and Christmas tree.

Well Spacing: The regulation of the number and location of wells over a reservoir as a conservation measure.

Well Stimulation: Any of several operations used to increase the production of a well.

Wildcat: A well drilled in an area where no oil or gas production exists. With present-day exploration methods and equipment, about one wildcat out of every six proves to be productive although not necessarily profitable.

Workover: One or more of a variety of remedial operations performed on a producing oil well to try to increase production. Examples of workover operations are deepening, plugging back, pulling and resetting the liner, squeeze-cementing, and so on.

Workover Fluids: A special drilling mud used to keep a well under control when it is being worked over. A workover fluid is compounded carefully so it will not cause formation damage.

APPENDIX C

DAMAGE CASE SUMMARIES

OH 49

State: Ohio

Region: 2

County/Parish: Ashtabula

City/Town: Hartsgrove

Test of Proof: Administrative and Scientific

Description

In 1982, drilling activities of an unnamed oil and gas company contaminated the well that served a house and barn owned by a Mr. Bean, who used the water for his dairy operations. Analysis done on the water well by the Ohio Department of Agriculture found high levels of barium, iron, manganese, sodium, and chlorides. (Barium is a common constituent of drilling mud.) Because the barium content of the water well exceeded State standards, Mr. Bean was forced to shut down his dairy operations. Milk produced at the Bean farm following contamination of the water well contained 0.63 mg/L of barium. Concentrations of chlorides, iron, sodium, and other residues in the water well were above the U.S. EPA's Secondary Drinking Water Standards. Mr. Bean drilled a new well, which also became contaminated. As of September 1984, Mr. Bean's water well was still showing signs of contamination from the drilling-related wastes. It is not known whether Mr. Bean was able to recover financially from the disruption of his dairy business.

Waste Analysis

Water samples from Mr. Bean's well showed concentrations of barium above the National Primary Drinking Water Standard; concentrations of chloride, iron, manganese, and residue above EPA's Secondary Drinking Water Standards; and high levels of sodium. Milk samples taken from Bean's dairy operation indicated barium contamination at 0.63 mg/L. A new well that was drilled also became contaminated.

Comments

API states that "The source of damage to freshwater wells is uncertain." Dave Flannery, representing independent oil and gas producers in Ohio, asserts that this discharge violates State regulations and that the State enforcement agency took appropriate action.

Violation of State Regulations: Yes

Documentation

References for case cited: Ohio EPA, Division of of Public Water Supply, Northeast District Office, interoffice communication from E. Mohr to M. Hilovsky describing test results on Mr. Bean's water well, 7/21/86. Letters from E. Mohr, Ohio EPA, to Mr. Bean and Mr. Hart explaining water sampling results, 10/20/82. Letter from Miceli Dairy Products Co. to E. Mohr, Ohio EPA, explaining test results from Mr. Bean's milk and water well. Letters from E. Mohr, Ohio EPA, to Mr. Bean explaining water sampling results from tests completed on 10/7/82, 2/2/83, 10/25/83, 6/15/84, 8/3/84, and 9/17/84. Generalized stratigraphic sequence of the rocks in the Upper Portion of the Grand River Basin.

OH 45

State: Ohio

Region: 2

County/Parish: Portage

City/Town: Windham

Test of Proof: Administrative and Scientific

Description

The Miller Sand and Gravel Co., though an active producer of sand and gravel, has also served as an illegal disposal site for oil field wastes. An investigation by the Ohio Department of Natural Resources found that the sand and gravel pits and the surrounding swamp were contaminated with oil and high-chloride produced waters. Ohio inspectors noted a flora kill of unspecified size. Ohio Department of Health laboratory analysis of soil and liquid samples from the pits recorded chloride concentrations of 269,000 mg/L. The surrounding swamp chloride concentrations ranged from 303 mg/L (upstream from the pits) to 60,000 mg/L (area around the pits). This type of discharge is prohibited by State regulations.

Waste Analysis

Samples taken from the pits showed conductivities >50,000 u/cm and chloride concentrations over 269,000 mg/L. Chloride concentrations in the surrounding swamp ranged from 303 mg/L (upstream from the pits) to 60,600 mg/L (area around the pits).

Comments

David Flannery, representing independent oil and gas producers in Ohio, notes that this discharge is prohibited by State regulation.

Violation of State Regulations: Yes

Documentation

References for case cited: Ohio EPA, Division of Wastewater Pollution Control, Northeast District Office, interoffice communication from E. Mohr to D. Hasbrauck, District Chief, concerning the results from sampling at the sand and gravel site. Ohio Department of Health, Environmental Sample Submission Reports from samples taken on 6/22/82.

OH 07

State: Ohio

Region: 2

County/Parish: Knox

City/Town: Howard

Test of Proof: Administrative and Scientific

Description

Equity Oil & Gas Funds, Inc., operates Well #1 on the the Engle Lease, Knox County. An Ohio DNR official inspected the site on April 5, 1985. There were no saltwater storage tanks on site to collect the high-chloride produced water that was being discharged from a plastic hose leading from the tank battery into a culvert that, in turn, emptied into a creek. The inspector took photos and samples. Both produced water and oil and grease levels were of sufficient magnitude to cause damage to flora and fauna, according to the notice of violation filed by the State. The inspector noted that a large area of land along the culvert had been contaminated with oil and produced water. The suspension order indicated that the "...violations present an imminent danger to public health and safety and are likely to result in immediate and substantial damage to natural resources." The operator was required by the State to "...restore the disturbed land surface and remove the oil from the stream in accordance with Section 1509.072 of Ohio Revised Statutes...."

Waste Analysis

Water samples taken from these locations yielded the following results: Sample #1, west side of Co. Rd. 35 at the culvert, indicated chloride, 43.0 mg/L; oil and grease, <1; Sample #2, from the east side of Co. Rd.

35 at the culvert, showed chloride, 45.0 mg/L; oil and grease, <1. Sample #3, from the end of the pipe that runs from the tank to the culvert, indicated chloride, 168,000 mg/L; oil and grease, present in the sample. Sample #4, east side of Co. Rd. 35 at the stream, indicated chloride, 2,060 mg/L; oil and grease, <1. Sample #5, from the mouth of the stream entering the creek, revealed chloride, 470 mg/L; oil and grease, 4,070 mg/L.

Comments

David Flannery, representing independent oil and gas producers in Ohio, notes that this discharge violates both State and Federal regulations.

Violation of State Regulations: Yes

Documentation

References for case cited: The Columbus Water and Chemical Testing Lab, lab reports. Ohio Department of Natural Resources, Division of Oil and Gas, Notice of Violation, 5/5/85.

OH 12

State: Ohio

Region: 2

County/Parish: Muskingum

City/Town: Hopewell

Test of Proof: Administrative, Legal, and Scientific

Description

Zenith Oil & Gas Co. operated Well #1 in Hopewell Township. The Ohio DNR issued a suspension order to Zenith in March of 1984 after State inspectors discovered produced water discharges onto the surrounding site from a breach in a produced water pit and pipe leading from the pit. A Notice of Violation had been issued in February 1984 but the violations were still in effect in March 1984. A State inspection of an adjacent site, also operated by Zenith Oil & Gas Co., discovered a plastic hose extending from one of the tank batteries discharging high-chloride produced water into a breached pit and onto the site surface. Another tank was discharging produced water from an open valve directly onto the site surface. State inspectors also expressed concern about lead and mercury contamination from the discharge. Lead levels in the discharge were 2.5 times the accepted level for drinking water, and mercury levels were 925 times the acceptable levels for drinking water, according to results filed for the State by a private laboratory. The State issued a suspension order stating that the discharge was "...causing contamination and pollution..." to the surface and subsurface soil, and in order to remedy the problem the operator would have to restore the disturbed land. (Ohio no longer allows the use of produced water disposal pits.)

Waste Analysis

A water sample taken at 10 feet below the pit from water covering the soil of the Mckee Lease Well #2 showed chloride, 6,300 mg/L; lead, 0.12 mg/L; and mercury, 1.85 mg/L.

Comments

David Flannery, representing independent oil and gas producers in Ohio, states that this discharge violated State regulations and that appropriate enforcement action was taken.

Violation of State Regulations: Yes

Documentation

References for case cited: Ohio Department of Natural Resources, Division of Oil and Gas, Suspension Order #84/07, 3/22/84. Muskingum County Complaint Form. Columbus Water and Chemical Testing Lab sampling report.

OH 38

State: Ohio

Region: 2

County/Parish: Perry

City/Town: Logan

Test of Proof: Administrative, Legal, and Scientific

Description

The Donofrio well was a production oil well with an annular disposal hookup fed by a 100-bbl produced water storage tank. In December 1975, shortly after completion of the well, tests conducted by the Columbus Water and Chemical Testing Lab on the Donofrio residential water well showed chloride concentrations of 4,550 ppm. One month after the well contamination was reported, several springs on the Donofrio property showed contamination from high-chloride produced water and oil, according to Ohio EPA inspections. On January 8, 1976, Ohio EPA investigated the site and reported evidence of oil overflow from the Donofrio well production facility, lack of diking around storage tanks, and the presence of several produced water storage pits. In 1986, 9 years after the first report of contamination, a court order was issued to disconnect the annular disposal lines and to plug the well. The casing recovered from the well showed that its condition ranged from fair to very poor. The casing was covered with rust and scale, and six holes were found.

Waste Analysis

Water samples from the Donofrio well indicated increasing chloride concentrations from 12/1/75 (4,550 ppm) to 3/25/76 (13,000 ppm). Water samples from springs on the Donofrio property also showed chloride contamination (ranging from 7,300 to 121,000 ppm), and on two occasions

(7/20/76 and 3/24/77) oil was seen flowing from the springs. Nine years later (9/26/84), the Donofrio well revealed 598 ppm of chloride.

Comments

Comments in the Docket by David Flannery and American Petroleum Institute (API) pertain to OH 38. Mr Flannery states that "...the water well involved in that case showed contamination levels which predated the commencement of annular disposal...." This statement refers to bacterial contamination of the well discovered in 1974. (EPA notes that the damage case discusses chloride contamination of the water well, not bacterial contamination.)

Violation of State Regulations: Yes

Documentation

Ohio Department of Natural Resources, Division of Oil and Gas, interoffice communication from M. Sharrock to S. Kell on the condition of the casing removed from the Donofrio well. Communication from Attorney General's Office, E.S. Post, discussing court order to plug the Donofrio well. Perry County Common Pleas Court Case #19262. Letter from R.M. Kimball, Assistant Attorney General, to Scott Kell, Ohio Department of Natural Resources, presenting case summary from 1974 to 1984. Ohio Department of Health lab sampling reports from 1976 to 1985. Columbus Water and Chemical Testing Lab, sampling reports from 12/1/75, 7/27/84, and 8/3/84.

WV 18

State: West Virginia

Region: 2

County/Parish: Doddridge

City/Town: Center Point

Test of Proof: Legal and Scientific

Description

Beginning in 1979, Allegheny Land and Mineral Company of West Virginia operated a gas well, #A-226, on the property of Ray and Charlotte Willey. The well was located in a corn field where cattle were fed in winter, and within 1,000 feet of the Willey's residence. The well was also adjacent to a stream known as the Beverlin Fork. Allegheny Land and Mineral also operated another gas well above the residence known as the #A-306, also located on property owned by the Willeys. Allegheny Land and Mineral maintained open reserve pits and an open waste ditch, which ran into Beverlin Fork. The ditch served to dispose of produced water, oil, drip gas, detergents, fracturing fluids, and waste production chemicals. Employees of the company told the Willeys that fluids in the pits were safe for their livestock to drink.

The Willeys alleged that their cattle drank the fluid in the reserve pit and became poisoned, causing abortions, birth defects, weight loss, contaminated milk, and death. Hogs were also allegedly poisoned, resulting in infertility and pig still-births, according to the complaint filed in the circuit court of Doddridge County by the Willeys against Allegheny Land and Mineral. The Willeys claimed that the soil on the farm was contaminated, causing a decrease in crop production and quality; that the ground water of the farm was contaminated, polluting the water well from which they drew their domestic water supply; and that the value of their real estate had been diminished as a result of these damages. Laboratory tests of soil and water from the property confirmed this contamination. The Willeys incurred laboratory expenses in having testing done on livestock, soil, and water. A judgment filed in the circuit court of Doddridge County was entered in 1983 wherein the Willeys were awarded a cash settlement in court for a total of $39,000 plus interest and costs.

Waste Analysis
Water analysis was done on fluid from a waste holding tank on the production site. The analysis revealed chlorides, 360,000 mg/L; phenols, 0.2 mg/L; sodium, 59,000 mg/L; aluminum, 2.0 mg/L; barium, 7.0 mg/L; and iron, 150 mg/L. A complete analysis is located in the file.

Violation of State Regulations: Yes

Comments
The West Virginia Department of Energy states that "...now the Division does not allow that type of practice, and would not let a landowner subvert the reclamation law."

Documentation
References for case cited: Complaint form filed in circuit court of Doddridge County, West Virginia, #81-c-18. Judgment form filed in circuit court of Doddridge County, West Virginia. Water quality summary of Ray Willey farm. Letter from D. J. Horvath to Ray Willey. Water analysis done by Mountain State Environmental Service. Veterinary report on cattle and hogs of Willey farm. Lab reports from National Veterinary Services Laboratories documenting abnormalities in Willey livestock.

WV 20

State: West Virginia

Region: 2

County/Parish: Wood

City/Town: Dallison

Test of Proof: Administrative and Legal

Description

On February 23, 1983, Tom Ancona, a fur trapper, filed a complaint concerning a fish kill on Stillwell Creek. A second complaint was also filed anonymously by an employee of Marietta Royalty Co. Ancona, accompanied by a State fisheries biologist, followed a trail consisting of dead fish, frogs, and salamanders up to a drilling site operated by Marietta Royalty Co., according to the complaint filed with the West Virginia DNR. There they found a syphon hose draining the drilling waste pit into a tributary of Stillwell Creek. Acid levels at the pit measured a pH of 4.0, enough to shock and kill aquatic life, according to West Virginia District Fisheries Biologist Scott Morrison. Samples and photographs were taken by the DNR. No dead aquatic life was found above the sample site. Marietta Royalty Co. was fined a total of $1,000 plus $30 in court costs.

Waste Analysis

Waste analysis indicated a pH of 4.0.

Comments

The West Virginia Department of Energy states that "This activity has now been regulated under West Virginia's general permit for drilling fluids. Under that permit there would have been no environmental damage."

Violation of State Regulations: Yes

Documentation

References for case cited: Complaint Form #6/170/83, West Virginia Department of Natural Resources, 2/25/83. West Virginia Department of Natural Resources Incident Reporting Sheet, 2/26/83. Sketches of Marietta drill site. Complaint for Summons or Warrant, 3/28/83. Summons to Appear, 3/18/83. Marietta Royalty Prosecution Report, West Virginia Department of Natural Resources. Interoffice memorandum containing spill investigation details on Marietta Royalty incident.

State: Pennsylvania

Region: 2

County/Parish: McKean, Forest and, Venango

City/Town: Lafayette and Keating

Test of Proof: Scientific

Description

The U.S. Fish and Wildlife Service conducted a survey of several streams in Pennsylvania from 1982-85 to determine the impact on aquatic life over a period of years resulting from discharge of oil field wastes to streams. The area studied has a history of chronic discharges of wastes from oil and gas operations. The discharges were primarily of produced water from production and enhanced recovery operations. The streams studied were Miami Run, South Branch of Cole Creek, Panther Run, Foster Brook, Lewis Run, and Pithole Creek. The study noted a decline downstream from discharges in all fish populations and populations of frogs, salamanders, and crayfish.

Waste Analysis

Data are all on file, but they are too extensive to list all measured levels (in mg/L) here. Ambient levels found at Foster Brook indicated that chloride, total hardness, and resistivity exceeded DER limits; at Lewis Run chlorides, manganese, osmotic pressure, and total dissolved solids exceeded DER limits; at Pithole Creek resistivity, total hardness, manganese, and chloride exceeded DER limits. At actual discharge points into Pithole Creek and Cherry Run, metals were found (e.g., cadmium, <1-280 ug/L; barium, 940-396,000 ug/L; chromium, <10-130 ug/L; and lead, <10-1,180 ug/L), as well as high levels of chloride (e.g., 124 to 45,250 mg/L).

Comments

David Flannery, on behalf of independent oil and gas producers in Pennsylvania, notes that these discharges are prohibited by State and Federal regulation.

Violation of State Regulations: Yes

Documentation

References for case cited: U.S. Fish and Wildlife, Summary of Data from Five Streams in Northwest Pennsylvania, 3/85. Background information on the streams selected for fish tissue analysis, undated but after 10/23/85. Tables 1 through 3 on point source discharge samples collected in the creeks included in this study, undated but after 10/30/84.

PA 09

State: Pennsylvania

Region: 2

County/Parish: McKean, Warren, Venango, and Elk

City/Town: Numerous

Test of Proof: Administrative and Scientific

Description

The U. S. EPA declared a four-county area (including McKean, Warren, Venango, and Elk counties) a major spill area in the summer of 1985. The area is the oldest commercial oil-producing region in the world. Chronic low-level releases have occurred in the region since earliest production and continues to this day. EPA and other agencies (e.g., U.S. Fish and Wildlife, Pennsylvania Fish and Game, U.S. Coast Guard) were concerned that continued discharge into the area's streams has already and will in the future have major environmental impact. The area is dotted with thousands of marginal stripper wells (producing a high ratio of produced water to oil), as well as thousands of abandoned wells and pits. In the Allegheny Reservoir itself, divers spotted 20 of 81 known improperly plugged or unplugged wells, 7 of which were leaking oily high-chloride produced water into the reservoir and have since been plugged. EPA is concerned that many others are also leaking oily produced water.

The U.S. Coast Guard (USCG) surveyed the forest for oil spills and produced water discharges, identifying those of particular danger to be cleaned immediately, by government if necessary. In the Allegheny Forest alone, USCG identified over 500 sites where oil is leaking from wells, pits, pipelines, or storage tanks. In 59 cases, oil was being discharged directly into streams; 217 sites showed evidence of past discharges and were on the verge of discharging again into the Allegheny Reservoir. Illegal disposal of oil field wastes has had a detrimental effect on the environment: "...there has been a lethal effect on trout streams and damage to timber and habitat for deer, bear and grouse." On Lewis Run, 52 discharge sites have been identified and the stream supports little aquatic life. Almost all streams in the Allegheny Forest have suppressed fish population as a "...direct result of pollution from oil and gas activity." (API notes that oil and produced water leaks into streams are prohibited by State and Federal regulations.)

Waste Analysis

See: PA 02. EPA, USCG, PaFG, USFW, and USGS conducted analyses and identified oil and gas waste streams and constituents in four counties. In 1986, USGS sampled the following sites: Allegheny Springs, where drinking wells were found to have elevated barium levels and undesirable methane concentrations; Penn DOT Roadside Rest Rt. 62, which indicated barium, 2.3 mg/L, chloride, 267 mg/L, and total dissolved solids, 750 mg/L (all above EPA limits); Sugar Grove, where abandoned oil wells located less than 200 feet from a contaminated domestic water well were found to contain high levels of aromatic hydrocarbons; and Tidioute

Borough, where a drinking water well showed high levels of metals, including iron, 7.2 mg/L and manganese, 0.5 mg/L.

Comments

Comments in the Docket by API pertain to PA 09. API states that "...litigation is currently pending with respect to this case in which questions have been raised about the factual basis for government action in this case."

Violation of State Regulations: No

Documentation

References for case cited: U.S. Geological Survey letter from Buckwalter to Rice concerning sampling of water in northern Pennsylvania, 10/27/86. Pennsylvania Department of Environmental Resources press release on analysis of water samples, undated but after 8/83. Oil and Water: When One of the By-products of High-grade Oil Production is a Low-grade Allegheny National Forest, It's Time to Take a Hard Look at Our Priorities by Jim Morrison, Pennsylvania Wildlife, Vol. 8, No. 1. Pittsburgh Press, "Spoiling a Wilderness," 1/22/84; "Oil Leaking into Streams at 300 Sites in Northwestern Area of the State," 1985. Warren Times, "Slick Issues Underscore Oil Cleanup in National Forest," 1986.

WV 17

State: West Virginia

Region: 2

County/Parish: Jackson

City/Town: Ripley

Test of Proof: Administrative and Scientific

Description

In 1982, Kaiser Gas Co. drilled a gas well on the property of Mr. James Parsons. The well was fractured using a typical fracturing fluid or gel. The residual fracturing fluid migrated into Mr. Parson's water well (which was drilled to a depth of 416 feet), according to an analysis by the West Virginia Environmental Health Services Lab of well water samples taken from the property. Dark and light gelatinous material (fracturing fluid) was found, along with white fibers. (The gas well is located less than 1,000 feet from the water well.) The chief of the laboratory advised that the water well was contaminated and unfit for domestic use, and that an alternative source of domestic water had to be found. Analysis showed the water to contain high levels of fluoride, sodium, iron, and manganese. The water, according to DNR officials, had a hydrocarbon odor, indicating the presence of gas. To date Mr. Parsons has not resumed use of the well as a domestic water source. (API states that this damage resulted from a malfunction of the fracturing process. If the fractures are not limited to the producing formation, the oil and gas are lost from the reservoir and are unrecoverable.)

Waste Analysis

Well water was analyzed and found to contain high levels of fluoride, sodium, iron, manganese, as well as elevated alkalinity. The water had a hydrocarbon odor indicating the presence of gas. Dark and light gelatinous material (fracturing fluid) was found along with white fibers.

Comments

Comments in the Docket pertain to WV 17, by David Flannery and West Virginia Department of Energy. Mr. Flannery states that "...this is an area where water problems have been known to occur independent of oil and gas operations." EPA notes that the "problems" Mr. Flannery is referring to are the natural high level of fluoride, alkalinity, sodium, and total dissolved solids in the water. However, the constituents of concern found in this water well were the gelatinous material associated with the fracturing process, and hydrocarbons. West Virginia Department of Energy states that the WVDOE "...had no knowledge that the Pittsburgh sand was a fresh water source." Also, WVDOE pointed out that WV Code 22B-1-20 "...requires an operator to cement a string of casing 30 feet below all fresh water zones." According to case study records, Kaiser Gas Co. did install a cement string of casing 30 feet below the Pittsburgh sand.

Violation of State Regulations: No

Documentation
References for case cited: Three lab reports containing analysis of water well. Letter from J. E. Rosencrance, Environmental Health Services Lab, to P. R. Merritt, Sanitarian, Jackson County, West Virginia. Letter from P. R. Merritt to J. E. Rosencrance requesting analysis. Letter from M. W. Lewis, Office of Oil and Gas, to James Parsons stating State cannot help in recovering expenses, and Mr. Parsons must file civil suit to recover damages. Water well inspection report = complaint. Sample report forms.

PA 08

State: Pennsylvania

Region: 2

County/Parish: Venango

City/Town: Belmar

Test of Proof: Legal and Scientific

Description
Civil suit was brought by 14 families living in the village of Belmar against a Meadville-based oil drilling company, Norwesco Development Corporation, in June 1986. Norwesco had drilled more than 200 wells near

Belmar, and residents of the village claimed that the activity had contaminated the ground water from which they drew their domestic water supply. The Pennsylvania Department of Environmental Resources and the Pennsylvania Fish Commission cited Norwesco at least 19 times for violations of State regulations. Norwesco claimed it was not responsible for contamination of the ground water used by the village of Belmar. Norwesco suggested instead that the contamination was from old, long-abandoned wells. The Pennsylvania Department of Environmental Resources (DER) agreed with Belmar residents that the contamination was from the current drilling operations. Ground water in Belmar had been pristine prior to the drilling operation of Norwesco. All families relying on the ground water lost their domestic water supply. The water from the contaminated wells would "...burn your eyes in the shower, and your skin is so dry and itchy when you get out." Families had to buy bottled water for drinking and had to drive, in some cases, as far as 30 miles to bathe. Not only were residents not able to drink or bathe using the ground water; they could not use the water for washing clothes or household items without causing permanent stains. Plumbing fixtures were pitted by the high level of total dissolved solids and high chloride levels.

In early 1986, DER ordered Norwesco to provide Belmar with an alternative water supply that was equal in quality and quantity to what the Belmar residents lost when their wells were contaminated. In November 1986 Norwesco offered a cash settlement of $275,000 to construct a new water system for the village and provided a temporary water supply.

Waste Analysis

Tests on one water well owned by the Neidirch family showed that it had 15 times the maximum level of chlorides (3,750 ppm) and 13 times the level of total dissolved solids (7,500 ppm) recommended by EPA. Other water wells in Belmar tested similarly.

Comments

David Flannery, on behalf of independent oil and gas producers in Pennsylvania, states that these activities are in violation of Federal and State regulations.

Violation of State Regulations: Yes

Documentation

References for case cited: Pittsburgh Press, "Franklin County Village Sees Hope after Bad Water Ordeal," 12/7/86. Morning News, "Oil Drilling Firm Must Supply Water to Homes," 1/7/86; "Village Residents Sue Drilling Company," 6/7/86.

WV 13

State: West Virginia

City/Town: Mt. Zion

Region: 2

County/Parish: Calhoun

Test of Proof: Administrative

Description

In early 1986 Tower Drilling land-applied the contents of a reserve pit to an area 100 feet by 150 feet. All vegetation died in the area where pit contents were directly applied, and three trees adjacent to the land application area were dying allegedly because of the leaching of high levels of chlorides into the soil. A complaint was made by a private citizen to the West Virginia DNR. Samples taken by West Virginia DNR of the contaminated soil measured 18,000 ppm chloride.

Waste Analysis

Analysis was done on affected soil. The results showed dissolved oxygen at 7.0 mg/L, specific conductance of 43,000 umhos/cm, and chloride at 18,000 mg/L.

Comments

Comments in the Docket by David Flannery and API pertain to WV 13. The statements by API and Mr. Flannery are identical. They state that it might not be "...possible to determine whether it was the chloride concentration alone which caused the vegetation stress." Also, they claim that the damage was short term and "...full recovery of vegetation was made." Neither commenter submitted supporting documentation.

Violation of State Regulations: No

Documentation

References for case cited: West Virginia Department of Natural Resources complaint form #6/131/86. Analytical report on soil analysis of kill area.

KY 01

State: Kentucky

Region: 2

County/Parish: Lawrence and Johnson

Test of Proof: Administrative and Scientific

Description

From April 29 through May 8, 1986, representatives of the U.S. EPA, Region IV, conducted a surface water investigation in the Blaine Creek watershed near Martha, Kentucky. The study was requested by the U.S. EPA

Water Management Division to provide additional baseline information on stream water quality conditions in the Blaine Creek area. Blaine Creek and its tributaries have been severely impacted by oil production activities conducted in the Martha oil field since the early 1900s. The Water Management Division issued an administrative order requiring that direct and indirect brine discharges to area streams cease by May 7, 1986.

For the study in 1986, 27 water chemistry sampling stations, of which 13 were also biological sampling stations, were established in the Blaine Creek watershed. Five streams in the study area were considered control stations. Biological sampling indicated that macroinvertebrates in the immediate Martha oil field area were severely impacted. Many species were reduced or absent at all stations within the oil field. Blaine Creek stations downstream of the oil field, although impacted, showed gradual improvement in the benthic macroinvertebrates. Control stations exhibited the greatest diversity of benthic macroinvertebrate species. Water chemistry results for chlorides generally indicated elevated levels in the Martha oil field drainage area. Chloride values in the affected area of the oil field ranged from 440 to 5,900 mg/L. Control station chloride values ranged from 3 to 42 mg/L.

In May of 1987, U.S. EPA, Region IV, conducted another surface water investigation of the Blaine Creek watershed. The study was designed to document changes in water quality in the watershed 1 year following the cessation of oil production activities in the Martha oil field. By May of 1987, the major operator in the area, Ashland Exploration, Inc., had ceased operations. Some independently owned production wells were still in service at this time. Chloride levels, conductivity, and total dissolved solids levels had significantly decreased at study stations within the Martha oil field. Marked improvements were observed in the benthic invertebrate community structures at stations within the Martha oil field. New species that are considered sensitive to water quality conditions were present in 1987 at most of the biological sampling stations, indicating that significant water quality improvements had occurred following cessation of oil production activities in the Martha field. Chloride levels in one stream in the Blaine Creek watershed decreased from 5,900 mg/L to 150 mg/L.

Water Analysis
Chloride values in the affected area of the oil field ranged from 440 to 5,900 mg/L. Control station chloride values ranged from 3 to 42 mg/L. Chloride levels in one stream in the Blaine Creek watershed decreased from 5,900 mg/L to 150 mg/L after cessation of operations.

Comments
None.

Violation of State Regulations: Yes

Documentation
References for case cited: Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1986. Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1987.

LA 67

State: Louisiana

City/Town: Abbeville

Region: 4

County/Parish: Vermilion

Test of Proof: Administrative, Legal, and Scientific

Description
In 1982, suit was brought on behalf of Dudley Romero et al. against operators of an oil waste commercial disposal facility, PAB Oil Co. The

plaintiffs stated that their domestic water wells were contaminated by wastes dumped into open pits in the PAB Oil Co. facility which were alleged to have migrated into the ground water, rendering the water wells unusable. Oil field wastes are dumped into the waste pits for skimming and separation of oil. The pits are unlined. The PAB facility was operating prior to Louisiana's first commercial oil field waste facility regulations. After promulgation of new regulations, the facility continued to operate for 2 years in violation of the new regulations, after which time the State shut down the facility.

The plaintiffs' water wells are downgradient of the facility, drilled to depths of 300 to 500 feet. Problems with water wells date from 1979. Extensive analysis was performed by Soil Testing Engineers, Inc., and U.S. EPA on the plaintiffs' water wells adjacent to the site to determine the probability of the well contamination coming from the PAB Oil Co. site. There was also analysis on surface soil contamination. Soil Testing Engineers, Inc., determined that it was possible for the wastes in the PAB Oil Co. pits to reach and contaminate the Romeros' water wells. Surface sampling around the perimeter of the PAB Oil Co. site found high concentrations of metals. Resistivity testing showed that plumes of chloride contamination in the water table lead from the pits to the water wells. Borings that determined the substrata makeup suggested that it would be possible for wastes to contaminate the Romeros' ground water within the time that the facility had been in operation if the integrity of the clay cap in the pit has been lost (as by deep excavation somewhere within it). The pit was 12 feet deep and within range to percolate into the water-bearing sandy soil.

Plaintiffs complained of sickness, nausea, and dizziness, and a loss of cattle. The case was settled out of court. The plaintiffs received $140,000 from PAB Oil Co.

Waste Analysis

Surface sampling around the perimeter of the PAB Oil Co. site found high concentrations of metals (in ppm). Upstream soil samples indicated: arsenic, 19.8; cadmium, 3.2; chromium, 31.3; copper, 14.8; lead, 13.2; nickel, 13.0; and zinc, 43.3. The PAB Oil Co. NE pit sample showed: arsenic, 16.2; cadmium, <18.0; beryllium, <18.0; chromium, 18.9; copper <18; lead, <27; nickel, <18; silver, <18; and zinc, 58.6. Romero well test results revealed: barium, 0.074; cadmium, <0.005; copper, <0.01; iron, 1.9; lead, <0.04; nickel, <0.02; and zinc, 0.26.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Soil Testing Engineers, Inc., Brine Study, Romero, et al., Abbeville, Louisiana, 10/19/82. U.S. EPA lab analysis of pits and wells, 10/22/81. Dateline, Louisiana: Fighting Chemical Dumping, by Jason Berry, May-June, 1983.

LA 20

State: Louisiana

Region: 4

County/Parish: Terrebonne

City/town: Not Applicable

Test of Proof: Scientific

Description

In 1984, the Glendale Drilling Co., under contract to Woods Petroleum, was drilling from a barge at the intersection of Taylor's Bayou and Cross Bayou. The operation was discharging drill cuttings and mud into the bayou within 1,300 feet of an active oyster harvesting area and State oyster seeding area. At the time of discharge, oyster harvests were in progress. (It is State policy in Louisiana not to grant permits for the discharge of drill cuttings within 1,300 feet of an active oyster harvesting area. The Louisiana Department of Environmental Quality does not allow discharge of whole mud into estuaries.)

A State Water Pollution Control Division inspector noted that there were two separate discharges occurring from the barge and a low mound of mud was protruding from the surface of the water beneath one of the discharges. Woods Petroleum had a letter from the Louisiana Department of Environmental Quality authorizing them to discharge the drill cuttings and associated mud, but this permit would presumably not have been issued if it had been known that the drilling would occur near an oyster harvesting area. While no damage was noted at time of inspection, there was great concern expressed by the Louisiana Oyster Growers Association; the Louisiana Department of Wildlife and Fisheries, Seafood Division; and some parts of the Department of Water Pollution Control Division of the Department of Environmental Quality. The concern of these groups stemmed from the possibility that the discharge of muds and cuttings with high content of metals may have long-term impact on the adjacent commercial oyster fields and the State oyster seed fields in nearby Junop Bay. In such a situation, metals can precipitate from the discharge, settling in progressively higher concentrations in the bayou sediments where the oysters mature. The bioaccumulation of these metals by the oysters can have an adverse impact on the oyster population and could also lead to human health problems if contaminated oysters are consumed.

The Department of Environmental Quality decided in this case to direct the oil company to stop the discharge of drill cuttings and muds into the bayou. In this instance, the Department of Environmental Quality ordered that a drill cutting barge be used to contain the remainder of the drill cuttings. The company was not ordered to clean up the mound of drill cuttings that it had already deposited in the bayou.

Waste Analysis

Split samples used in laboratory analysis of both discharges indicated elevated levels of chromium.

Comments

The Louisiana Office of Conservation notes that "Generally, drill cuttings discharged with weighted drilling fluids (containing borite, calcium chloride, etc.) are allowed in brackish and saline areas provided the discharge does not take place within 1,300 feet of an active oyster lease or seed bed...." In freshwater marshes, drill cuttings can also be discharged if the operator can meet stringent conditions preventing excessive turbidity. In the future, WPCD plans to issue a general permit for drilling fluid discharges in tidally affected brackish and saline areas.

Violation of State Regulations: No

Documentation

References for case cited: Louisiana Department of Environmental Quality, Water Pollution Control Division, Office of Water Resources, internal memorandum, 6/3/85.

LA 45

State: Louisiana

Region: 4

County/Parish: Lafourche

City/Town: Lewistown

Test of Proof: Scientific

Description

Two Louisiana Water Pollution Control inspectors surveyed a swamp adjacent to a KEDCO Oil Co. facility to assess flora damage recorded on a Notice of Violation issued to KEDCO on 3/13/81. The Notice of Violation discussed brine discharges into an adjacent canal that emptied into a cypress swamp from a pipe protruding from the pit levee. Analysis of a sample collected by a Mr. Martin, the complainant, who expressed concern over the high-chloride produced water discharge into the canal he used to obtain water for his crawfish pond, showed salinity levels of 32,000 ppm (seawater is 35,000 ppm).

On April 15, 1981, the Water Pollution Control inspectors made an effort to measure the extent of damage to the trees in the cypress swamp. After surveying the size of the swamp, they randomly selected a compass bearing and surveyed a transect measuring 200 feet by 20 feet through the swamp. They counted and then classified all trees in the area according to the degree of damage they had sustained. Inspectors found that "...an approximate total area of 4,088 acres of swamp was severely damaged." Within the randomly selected transect, they classified all trees according to the degree of damage. Out of a total of 105 trees, 73 percent were dead, 18 percent were stressed, and 9 percent were normal. The inspectors' report noted that although the transect ran through a heavily damaged area, there were other areas much more severely impacted. They therefore concluded, based upon data collected and firsthand observation, that the percentages of damaged trees recorded "...are a representative, if not conservative, estimate of damage over the entire affected area." In the opinion of the inspectors, the discharge of produced water had been occurring for some time, judging by the amount of damage sustained by the trees. KEDCO was fined $9,500 by the State of Louisiana and paid $4,500 in damages to the owner of the affected crawfish farm.

Waste Analysis

See: LA 38. At the time of the most recent inspection on 2/2/81, field testing for salinity in the water revealed that the canal had 19,000 ppm; salinity under a railroad trestle in the canal, at the point where the canal empties into the cypress swamp, was 39.5 ppm. Analysis of the sample collected by Mr. Martin (the complainant who expressed concern over the produced water discharge into the canal he used to obtain water for his crawfish pond) at the time of the discharge into the canal on 1/30/81 showed salinity at 32,000 ppm.

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, Cormier and St. Pe to Givens concerning damage evaluation of swamp near the KEDCO Oil Co. facility, 6/24/81. Notice of Violation, Water Pollution Control Log #2-8-81-21.

LA 15

State: Louisiana

Region: 4

County/Parish: Terrebonne

City/Town: Thibodeaux

Test of Proof: Administrative and Scientific

Description

Sun Oil Co. operates a site located in the Chacahoula Field. A Department of Natural Resources inspector noted a site configuration during an inspection (6/25/82) of a tank battery surrounded by a pit levee and a pit (30 yards by 50 yards). The pit was discharging produced water into the adjacent swamp in two places, over a low part in the levee and from a pipe that had been put through the ring levee draining directly into the swamp. Produced water, oil, and grease were being discharged into the swamp. Chloride concentrations from samples taken by the inspectors ranged from 2,948 ppm to 4,848 ppm, and oil and grease concentrations measured 12.6 ppm to 26.7 ppm. The inspector noted that the discharge into the swamp was the means by which the company drains the tank battery ring levee area. A notice of violation was issued to Sun Oil by the Department of Natural Resources.

Waste Analysis

Sample analysis indicated the following results: at the discharge pipe from the tank to the pit, chloride at 75,230 ppm, conductivity, 110,000 umhos; at the discharge from the pit to the swamp, chloride at 4,748 ppm, conductivity, 100,000 umhos; at the discharge from the tank to the pit, chemical oxygen demand, 5,909 ppm, oil and grease, 12.6 ppm; and at the discharge from the large pipe leading from the tank battery pit area, chloride at 2,948 ppm, conductivity, 9,700 umhos, chemical oxygen demand, 369 ppm, and oil and grease, 26.7 ppm.

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo from Cormier to Givens, 8 15 82, concerning Sun Oil Co. brine discharge. Chacahoula Field. Log #2-8-81-122. Lab analysis, 7/2/82.

LA 64

State: Louisiana

Region: 4

County/Parish: St. Mary

City/Town: Not Applicable

Test of Proof: Scientific

Description

Dr. Wilma Subra documented damage to D.T. Caffery's sugar cane fields adjacent to a production site, which included a saltwater disposal well, in St. Mary Parish. The operator was Sun Oil. The documentation was collected between July of 1985 and November of 1986, and included reports of salt concentrations in soil at various locations in the sugar cane fields, along with descriptions of accompanying damage. Dr. Subra noted that the sugar cane fields had various areas that were barren and contained what appeared to be sludge. The production facility is upgradient from the sugar cane fields, and Dr. Subra surmised that produced water was discharged onto the soil surface from the facility and that a plume of salt contamination spread downgradient, thereby affecting 7.3 acres of sugar cane fields, over a period of a year and a half.

In July 1985, Dr. Subra noted that the cane field, though in bad condition, was predominantly covered with sugar cane. There were, however, weeds or barren soil covering a portion of the site. The patch of weeds and barren soil matched the area of highest salt concentration. In the area where the topography suggested that brine concentrations would be lowest, the sugar cane appeared healthy. Subsequent field investigation and soil sampling conducted by Dr. Subra in November of 1986 found the field to be nearly barren, with practically no sugar cane growing. Dr. Subra measured concentrations of salts in the soil ranging from a low of 1,403 ppm to 35,265 ppm at the edge of the field adjacent to the oil operation. Sun has undertaken a reclamation project to restore the land. It is estimated that the project will take 2 to 3 years to complete. In the interim, Sun Oil will pay the sugar cane farmer for loss of crops.

Waste Analysis

All sampling done for salt was conducted on 11/15/86. The following results were obtained: Twelve soil samples from the cane field downgradient indicated salt concentrations on the perimeter of the facility near the produced water storage tank ranging from 5,259 to 71,940 ppm; samples from the middle of the cane field ranged from 1,403 to 6,478 ppm, and samples from the extreme edge of the field ranged from 20,186 to 35,265 ppm; four water samples from the cane field at the perimeter of the facility near the produced water storage tank ranged from 1,774 to 3,383 ppm; and one sample near the edge of the field showed 2,210 ppm.

Comments

API states that an accidental release occurred in this case. EPA records show this release lasted 2 years.

Violation of State Regulations: No

Documentation

References for case cited: Documentation from Dr. Wilma Subra, including a series of maps documenting changes in the sugar cane over a period of time, 12/86. Maps showing location of sampling and salt concentrations.

LA 90

State: Louisiana

Region: 4

County/Parish: Vermilion

City/Town: Abbeville

Test of Proof: Administrative, Legal, and Scientific

Description

Chevco-Kengo Services, Inc., operates a centralized disposal facility near Abbeville, Louisiana. Produced water and other wastes are transported from surrounding production fields by vacuum truck to the facility. Complaints were filed by private citizens alleging that discharges from the facility were damaging crops of rice and crawfish, and that the facility represented a threat to the health of nearby residents. An inspection of the site by the Water Pollution Control Division of the Department of Natural Resources found that a truck washout pit was emptying oil field wastes into a roadside ditch flowing into nearby coulees.

Civil suit was brought by private citizens against Chevco-Kengo Services, Inc., asking for a total of $4 million in property damages, past and future crop loss, and exemplary damages. Lab analysis performed by the Department of Natural Resources of waste samples indicated high metals content of the wastes, especially in samples taken from the area near the facility and in the adjacent rice fields, indicating that the discharge of wastes from the facility was the source of damage to the surrounding land. The case is in litigation.

Waste Analysis

Dr. Subra's analysis revealed these concentrations in crawfish tails from the adjacent pond: barium, 18 ppm, zinc, 16.5 ppm; from the roadside ditch on the south side of Parish Rd. P-3-5, 0.3 miles west of the Chevco site: salt, 854 ppm, barium, 1,250 ppm, chromium, 15 ppm, lead, 16 ppm, zinc, 548 ppm; from the roadside ditch on the west side of the Chevco main entrance from Parish Rd. P-3-5: barium, 1,190 ppm, chromium, 301 ppm, lead, 184 ppm, zinc, 1,203 ppm; from the roadside ditch directly across Parish Rd. P-3-5 from the Chevco outfall: barium, 2,200 ppm, chromium, 8.8 ppm, lead, 38 ppm, and zinc, 190 ppm. Rice field ranges were: zinc, 13.7 to 29.5 ppm; lead, 6 to 26 ppm; chromium, 4.5 to 12.2 ppm; and barium, 65 to 230 ppm.

Comments

API states that these discharges were accidental.

Violation of State Regulations: Yes

Documentation

References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, lab analysis, and photographs, 8/25/83. Letter from Westland Oil Development Corp. to Louisiana Department of Natural Resources, 4/15/83.

AR 07

State: Arkansas

Region: 4

County/Parish: Union

City/Town: El Dorado

Test of Proof: Administrative

Description

An oil production unit operated by Mr. J.C. Langley was discharging oil and produced water in large quantities onto the property of Mr. Melvin Dunn and Mr. W. C. Shaw. The oil and produced water discharge allegedly caused severe damage to the property, interfered with livestock on the property, and delayed construction of a planned lake. Mr. Dunn had spoken repeatedly with a company representative operating the facility concerning the oil and produced water discharge, yet no changes occurred in the operation of the facility A complaint was made to Arkansas Department of Pollution Control and Ecology (ADPCE), the operator was informed of the situation, and the facility was brought into compliance. Mr. Dunn then hired a private attorney in order that remedial action would be taken. It is not known whether the operator cleaned up the damaged property.

Waste Analysis

Not available.

Comments

API states that this incident constituted a spill and is therefore a non-RCRA issue.

Violation of State Regulations: Yes

Documentation

References for case cited: Arkansas Department of Pollution Control and Ecology (ADPCE) Complaint form, #EL 1721, 5/14/84. Letter from Michael Landers, attorney to Mr. Dunn, requesting investigation from Wayne Thomas concerning Langley violations. Letter from J. C. Langley to Wayne Thomas, ADPCE, denying responsibility for damages of Dunn and Shaw property, 6/5/84. Certified letter from Wayne Thomas to J. C. Langley discussing violations of facility and required remedial actions, 5/30/84. Map of violation area, 5/29/84. ADPCE oil field waste survey documenting unreported oil spill on Langley unit, 5/25/84. Letter from Michael Landers, attorney to ADPCE, discussing damage to property of Dunn and Shaw, 5/11/84.

AR 10

State: Arkansas

Region: 4

County/Parish: Ouachita

City/Town: Louann

Test of Proof: Administrative

Description

On September 20, 1984, an anonymous complaint was filed with ADPCE concerning the discharge of oil and produced water in and near Smackover Creek from production units operated by J. S. Beebe Oil Account. Upon investigation by ADPCE, it was found that salt water was leaking from a saltwater disposal well located on the site. Mr. Beebe wrote a letter stating his willingness to correct the situation. On November 16, 1984, the site was again investigated by ADPCE, and it was found that pits on location were being used as the primary disposal facility and were overflowing and leaking into Smackover Creek. The ADPCE issued a Notice of Violation (LIS 84-066), and noted that the pits were below the creek level and overflowed into the creek when heavy rains occurred. One pit was being siphoned over the pit wall, while waste from another pit was flowing onto the ground through an open pipe. The floors and walls of the pits were saturated, allowing seepage of waste from the pits. ADPCE ordered Mr. Beebe to shut down production and clean up the site and fined him $10,500.

Waste Analysis
Not available.

Comments
API states that this case represents a violation of Arkansas' rules and regulations.

Violation of State Regulations: Yes

Documentation
References for case cited: ADPCE complaint form #EL 1792, 9/20/84, and 8/23/84. ADPCE inspection report, 9/5/84. Letter from ADPCE to J. S. Beebe outlining first run of violations, 9/6/84. Letter stating willingness to cooperate from Beebe to ADPCE, 9/14/84. ADPCE complaint form #EL 1789, 9/19/84. ADPCE inspection report, 9/25 and 9/26/84. ADPCE complaint form #EL 1822, 11/16/84. ADPCE Notice of Violation, Findings of Fact, Proposed Order and Civil Penalty Assessment, 11/21/84. Map of area. Miscellaneous letters.

AR 04

State: Arkansas

Region: 4

County: Miller

City/Town: Not Applicable

Test of Proof: Administrative and Scientific

Description
In 1983 and again in 1985, James M. Roberson, an oil and gas operator, was given surface access by the Arkansas Game and Fish Commission for

drilling in areas in the Sulphur River Wildlife Management Area (SRWMA), but was not issued a drilling permit by either of the State agencies that share jurisdiction over oil and gas operations. Surface rights are owned by the Arkansas Game and Fish Commission. The Commission attempted to write its own permits for this operation to protect the wildlife management area resources. Mr. Roberson repeatedly violated the requirements contained in these surface use permits, and the Commission also determined that he was in violation of general State and Federal regulations applicable to his operation in the absence of OGC or ADPCE permits. These violations led to release of oil and high-chloride produced water into the wetland areas of the Sulphur River and Mercer Bayou from a leaking saltwater disposal well and illegal produced water disposal pits maintained by the operator.

Oil and saltwater damage to the area was documented in a study conducted by Hugh A. Johnson, Ph.D., a professor of biology at Southern Arkansas University. His study mapped chloride levels around each well site and calculated the affected area. The highest chloride level recorded in the wetland was 9,000 ppm (native vegetation begins to be stressed from exposure to 250 ppm chlorides). He found that significant areas around each well site had dead or stressed vegetation related to excessive chloride exposure. The Game and Fish Commission fears that continued discharges of produced water and oil in this area will threaten the last remaining forest land in the Red River bottoms.

Waste Analysis

Oil and saltwater damage were documented in a study of the area by Hugh A. Johnson, Ph.D. The study mapped chloride levels around each well site and calculated the area of damage. Highest chlorides in wetlands were 9,000 ppm. Significant areas around each well site had dead or stressed vegetation due to saltwater exposure.

Comments

API states that the Arkansas Water and Air Pollution Act gives authority at several levels to require cleanup of these illegal activities and to prevent further occurrences. EPA notes that while the authority exists, an effective implementation mechanism appears to be lacking.

Violation of State Regulations: Yes

Documentation

References for case cited: Letter from Steve Forsythe, Department of the Interior (DOI), to Pat Stevens, Army Corps of Engineers (ACE), stating that activities of Mr. Roberson have resulted in significant adverse environmental impacts and disruptions and that DOI recommends remedial action be taken. Chloride Analysis of Soil and Water Samples of Selected Sites in Miller County, Arkansas, by Hugh A. Johnson, Ph.D, 10/22/85. Letter to Pat Stevens, ACE, from Dick Whittington, EPA, discussing damages caused by Jimmy Roberson in Sulphur River Wildlife Management Area (SRWMA) and recommending remedial action and denial of new permit application. Oil and Gas well drilling permits dated 1983 and 1985 for Roberson activities. Numbers of letters and complaints addressing problems in SRWMA resulting from activities of James Roberson. Photographs. Maps.

AR 12

State: Arkansas

Region: 4

County/Parish: Columbia

City/Town: Stephens

Test of Proof: Administrative

Description

On September 19, 1984, Mr. James Tribble made a complaint to the Arkansas Department of Pollution Control and Ecology concerning salt water that was coming up out of the ground in his yard, killing his grass and threatening his water well. There are many oil wells in the area, and water flooding is a common enhanced recovery method at these sites. Upon inspection of the wells nearest to his residence, it was discovered that the operator, J. C. McLain, was injecting salt water into an unpermitted well. The salt water was being injected into the casing, or annulus, not into tubing. Injection into the unsound casing allegedly allowed migration into the freshwater zone. A produced water pit at the same site was near overflowing. State inspectors later noted in a followup inspection that the violations had been corrected. No fine was levied.

Waste Analysis
Not available.

Comments
API notes that this case represents a violation of Arkansas rules and regulations.

Violation of State Regulations: Yes

Documentation
References for case cited: ADPCE Complaint form, #EL 1790, 9/19/84. ADPCE inspection report, 9/20/84. Letter from ADPCE to Mr. J. C. McLain describing violations and required corrective action, 9/21/84. ADPCE reinspection report, 10/11/84.

MI 05

State: Michigan

Region: 5

County: Osceola

City/Town: Hersey

Test of Proof: Scientific

Description

In June 1983, a water well owned by Mrs. Geneva Brown was tested after she had filed a complaint to the Michigan Geological Survey. After responding, the Michigan Geological Survey found a chloride concentration of 490 ppm in the water. Subsequent sampling from the water well of a neighbor, Mrs. Dodder, showed that her well measured 760 ppm chloride in August. There are a total of 15 oil and gas wells in the area surrounding the contaminated water wells. Only five of the wells are still producing, recovering a combination of oil and produced water. The source of the pollution was evidently the H.E. Trope, Inc., crude oil separating facilities and produced water storage tanks located upgradient from the contaminated water wells. Monitoring wells were installed to confirm the source of the contamination. Stiff diagrams were used to confirm the similarity of the constituents of the formation brine and the chloride contamination of the affected water wells. Sample results located two plumes of chloride contamination ranging in concentration from 550 to 1,800 ppm that are traveling in a southeasterly direction downgradient from the produced water storage tanks and crude oil separator facilities owned by H.E. Trope.

Waste Analysis

Water well samples from the domestic wells owned by G. Brown and M. Dodder showed chloride concentrations ranging from 490 to 550 ppm and 550 to 800 ppm, respectively. Monitoring wells used in the study showed chloride concentrations ranging from 550 to 1,800 ppm. A produced water sample from the storage tanks measured 191,000 ppm.

Comments

API states that this case appears to represent a non-RCRA issue as damage was due to leaks or spills of produced water.

Violation of State Regulations: Yes

Documentation

References for case cited: Open file report, Michigan Department of Natural Resources, Investigation of Salt-Contaminated Groundwater in Cat Creek Oil Field, Hersey Township, conducted by D. W. Forstat, 1984. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

MI 06

State: Michigan

Region: 5

County/Parish: Muskegon

City/Town: Laketon

Test of Proof: Scientific

Description

In April 1980, residents of Green Ridge Subdivision, located in Section 15, Laketon Township in Muskegon County, complained of bad-tasting water from their domestic water wells. Some wells sampled by the local health department revealed elevated chloride concentrations. Because of the proximity of the Laketon Oil Field, an investigation was started by the Michigan Geological Survey. The Laketon Oil Field consists of dry holes, producing oil wells, and a produced water disposal well, the Harris Oil Corp. Lappo #1. Oil wells produce a mixture of oil and produced water. The produced water is separated and disposed of by gravity in the brine disposal well and is then placed back in the producing formation. After reviewing monitoring well and electrical resistivity survey data. the Michigan Geological Survey concluded that the source of the contamination was the Harris Oil Corp. Lappo #1 produced water disposal well. which was being operated in violation of UIC regulations.

Waste Analysis

Water samples from observation and residential wells indicated produced water contamination from the Harris Oil Corp. Lappo #1 disposal well. Chloride in the sampled residential wells ranged from background concentrations to 1,000 ppm. Monitor wells showed chloride concentrations ranging from 65 to 19,000 ppm.

Comments

API notes that the UIC program is administered by EPA Region V in Michigan.

Violation of State Regulations: Yes

Documentation

References for case cited: Open file report, Michigan Department of Natural Resources. Investigation of Salt-Contaminated Groundwater in Green Ridge Subdivision, Laketon Township, conducted by B. P. Shirey, 1980. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

MI 04

State: Michigan

Region: 5

County/Parish: Calhoun

City/Town: Pennfield

Test of Proof: Scientific

Description

Drilling operations at the Burke Unit #1 caused the temporary chloride contamination of two domestic water wells and longer lasting chloride contamination of a third well closer to the drill site. The operation was carried out in accordance with State regulations and special site restrictions required for urban areas, using rig-engines equipped with mufflers, steel mud tanks for containment of drilling wastes, lining for earthen pits that may contain salt water, and the placement of a conductor casing to a depth of 120 feet to isolate the well from the freshwater zone beneath the rig.

The drilling location is underlain by permeable surface sand, with bedrock at a depth of less than 50 feet. Contamination of the ground water may have occurred when material flushed from the mud tanks remained in the lined pit for 13 days before removal. (The material contained high levels of chlorides, and liners can leak.) According to the State report, this would have allowed sufficient time for contaminants to migrate into the freshwater aquifer. A leak from the produced water storage tank was also reported by the operator to have occurred before the contamination was detected in the water wells. One shallow well was less than 100 feet directly east of the drill pit area and 100 to 150 feet southeast of the produced water leak site. Chloride concentrations in this well measured by the Michigan Geological Survey were found to range from 750 ppm (9/5/75) to 1,325 ppm (5/23/75). By late August, two of the wells had returned to normal, while the third well still measured 28 times its original background concentration of chloride.

Waste Analysis

Before the drilling operation began, the water well owned by H. Rop showed chloride concentrations of 27 ppm on 12/5/74. Five months after drilling was completed, the Rob well showed chloride concentrations of 1,325 ppm on 5/23/75. Chloride concentrations decreased with time to 750 ppm on 9/5/75.

Comments

API notes that since 1975, Michigan has adopted regulations requiring pits to be lined in most instances.

Violation of State Regulations: Yes

Documentation

References for case cited. Open file report, Michigan Department of Natural Resources, Report on Ground-Water Contamination, Sullivan and Company, J.D. Burke No. 1, Pennfield Township, conducted by J. R. Byerlay, 1976. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

KS 01

State: Kansas

Region: 6

County: Montgomery

City/Town: Not applicable

Test of Proof: Administrative and Legal

Description

Temple Oil Company and Wayside Production Company operate a number of oil production leases in Montgomery County. The leases were operated with illegally maintained saltwater containment ponds, improperly abandoned reserve pits, unapproved emergency saltwater pits, and improperly abandoned saltwater pits. Numerous oil and saltwater spills were recorded during operation of the sites. Documentation of these incidents started in 1977 when adjacent landowners began to complain about soil pollution, vegetation kills, fish kills, and pollution of freshwater streams due to oil and saltwater runoff from these sites. The leases also contain a large number of abandoned, unplugged wells, which may pose a threat to ground water.[1] Complaints were received by the Conservation Division, Kansas Department of Health and the Environment (KDHE), Montgomery County Sheriff, and Kansas Fish and Game Commission. A total of 39 violations on these leases were documented between 1983 and 1984.

A water sample taken by KDHE from a 4 1/2-foot test hole between a freshwater pond and a creek on one lease showed chloride concentrations of 65,500 ppm. Water samples taken from pits on other leases showed chloride concentrations ranging from 5,000 to 82,000 ppm.

The Kansas Corporation Commission issued an administrative order in 1984, fining Temple and Wayside a total of $80,000. Initially, $25,000 was collected, and the operators could reapply for licenses to operate in Kansas in 36 months if they initiated adequate corrective measures. The case is currently in private litigation. The Commission found that no progress had been made toward bringing the leases into compliance and, therefore, reassessed the outstanding $55,000 penalty. The Commission has since sought judicial enforcement of that penalty in the District Court, and a journal entry has been signed and was reviewed by the Commission and is now ready to be filed in District Court. Additionally,

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1 Comments in the Docket by the Kansas Corporation Commission (Beatrice Stong) pertain to KS 01. With regard to the abandoned wells, Kansas Corporation Commission states that these wells are "...cemented from top to bottom...", they have "...limited resource energy,..." and the static fluid level these reservoirs could sustain are "...well below the location of any drinking or usable water"

in a separate lawsuit between the landowners, the lessors, and the Temples regarding operation of the leases, the landowners were successful and the leases have reverted back to the landowners. The new operators are prevented from operating without Commission authority.

Waste Analysis

Water sampled from a 4 1/2-foot test hole between a freshwater pond and a creek on the Fowler's lease showed soil in the unsaturated zone with chloride concentrations of 65,500 ppm. Water samples taken from pits on the owners' leases (the Fowler's and others) showed chloride concentrations ranging from 5,000 to 82,000 ppm.

Comments

Comments in the Docket by the Kansas Corporation Commission (Beatrice Stong) pertain to KS 01. With regard to the abandoned wells, Kansas Corporation Commission states that these wells are "...cemented from top to bottom...", they have "...limited resource energy..." and the static fluid level these reservoirs could sustain are "...well below the location of any drinking or usable water."

Violation of State Regulations: Yes

Documentation

References for case cited: The Kansas Corporation Commission Court Order describing the evidence and charges against the Temple Oil Co., 5/17/84.

KS 08

State: Kansas

Region: 6

County/Parish: Montgomery

City/Town: Not Applicable

Test of Proof: Administrative and Legal

Description

On January 31, 1986, the Kansas Department of Health and the Environment inspected the Reitz lease in Montgomery County, operated by Marvin Harr of El Dorado, Arkansas. The lease included an unpermitted emergency pond containing water that had 56,500 ppm chlorides. A large seeping area was observed by KDHE inspectors on the south side of the pond, allowing the flow of salt water down the slope for about 30 feet. The company was notified and was asked to apply for a permit and install a liner because the pond was constructed of sandy clay and sandstone. The operator was directed to immediately empty the pond and backfill it if a liner was not installed. On February 24, the lease was reinspected by KDHE and the emergency pond was still full and actively seeping. It appeared that the lease had been shut down by the operator. A "pond order" was issued by KDHE requiring the company to drain and backfill the pond. On April 29, the pond was still full and seeping.

Water samples taken from the pit by KDHE showed chloride concentrations of from 30,500 ppm (4/29/86) to 56,500 ppm (1/31/86). Seepage from the pit showed chloride concentrations of 17,500 ppm (2/24/86). The Kansas Department of Health and the Environment stated that "...the use of the pond...has caused or is likely to cause pollution to the soil and the waters of the State." An administrative penalty of $500 was assessed against the operator, and it was ordered that the pond be drained and backfilled.

Waste Analysis

Water samples taken from the pit indicated chloride concentrations ranging from 30,500 ppm (4/29/86) to 56,500 ppm (1/31/86). Leakage from the pit showed a chloride concentration of 17,500 ppm (2/24/86).

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: Kansas Department of Health and Environment Order assessing civil penalty, in the matter of Marvin Harr, Case No. 86-E-77, 6/10/86. Pond Order issued by Kansas Department of Health and Environment, in the matter of Marvin Harr, Case No. 86-PO-008, 3/21/86.

KS 05

State: Kansas

Region: 6

County/Parish: Osborne

City/Town: Paradise

Test of Proof: Administrative and Scientific

Description

Between February 9 and 27, 1986, the Elliott #1 was drilled on the property of Mr. Lawrence Koelling. The Hutchinson Salt member, an underground formation, was penetrated during the drilling of Elliott #1. The drilling process dissolved between 100 and 200 cubic feet of salt, which was disposed of in the unlined reserve pit. The reserve pit lies 200 feet away from a well used by Mr. Koehling for his ranching operations. Within a few weeks of the drilling of the Elliott #1, Mr. Koelling's nearby well began to pump water containing a saltwater drilling fluid.

Ground water on the Koehling ranch has been contaminated with high levels of chlorides allegedly because of leaching of the reserve pit fluids into the ground water. Water samples taken from the Koehling livestock water well by the KCC Conservation Division showed a chloride concentration of 1,650 mg/L. Background concentrations of chlorides were in the range of 100 to 150 ppm. It is stated in a KCC report, dated November 1986, that further movement of the saltwater plume can be anticipated, thus polluting the Koehling domestic water well and the water well used by a farmstead over 1 mile downstream from the Koehling ranch. It is also stated in this KCC report that other wells drilled in the area using unlined reserve pits would have similarly affected the ground water.

The KCC now believes the source of ground-water contamination is not the reserve pit from the Elliott #1. The KCC has drilled two monitoring wells, one 10 feet from the edge of the reserve pit location and the other within 400 feet of the affected water well, between the affected well and the reserve pit. The monitoring well drilled 10 feet from the reserve pit site tested 60 ppm chlorides. (EPA notes that it is not known if this monitoring well was located upgradient from the reserve pit.) The monitoring well drilled between the affected well and the reserve pit tested 750 ppm chlorides. (EPA notes that the level of chlorides in this monitoring well is more than twice the level of chlorides allowed under the EPA drinking water standards). The case is still open, pending further investigation. EPA believes that the evidence presented to date does not refute the earlier KCC report, which cited the reserve pit as the source of ground-water contamination, since the recent KCC report does not suggest an alternative source of contamination.

Waste Analysis

Water samples from the Koehling livestock water well showed chloride concentrations of 900 and 950 ppm. Background concentrations of chloride would be in the range of 100 to 150 ppm.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Summary Report, Koehling Water Well Pollution, 22-10-15W, KCC, Conservation Division, Jim Schoof, Chief Engineer, 11/86.

KS 03

State: Kansas

Region: 6

County/Parish: Kingman

City/Town: Wichita

Test of Proof: Administrative and Scientific

Description

Mr. Leslie, a private land owner in Kansas, suspected that chloride contamination of a natural spring occurred as a result of the presence of an abandoned reserve pit used when Western Drilling Inc. drilled a well (Leslie #1) at the Leslie Farm. Drilling in this area required penetration of the Hutchinson Salt member, during which 200 to 400 cubic feet of rock salt was dissolved and discharged into the reserve pit. The ground in the area consists of highly unconsolidated soils, which would allow for migration of pollutants into the ground water. Water at the top of the Leslie #1 had a conductivity of 5,050 umhos. Conductivity of the spring water equaled 7,250 umhos. As noted by the KCC, "very saline water" was coming out of the springs. Conductivity of 2,000 umhos will damage soil, precluding growth of vegetation. No fines were levied in this case as there were no violations of State rules and regulations. The Leslies filed suit in civil court and won their case for a total of $11,000 from the oil and gas operator.

Waste Analysis

Salt water at the top of the Leslie #1 had conductivity of 5,050 umhos. Conductivity of spring water was 7,250 umhos. The KCC noted "very saline water" coming out of the springs. It also indicated that conductivity of 2,000 umhos will damage soil, precluding the growth of vegetation.

Comments

API states that KDHE had authority over pits at this time. The KCC now requires permits for such pits.

Violation of State Regulations: No

Documentation

Reference for case cited: Final Report, Gary Leslie Saltwater Pollution Problem, Kingman County, KCC Conservation Division, Jim Schoof, Chief Engineer, 9/86. Contains letters, memos, and analysis pertaining to the case.

KS 06

State: Kansas

Region: 6

County/Parish: Graham

City/Town: Morland

Test of Proof: Scientific

Description

On July 12, 1981, the Kansas Department of Health and the Environment (KDHE) received a complaint from Albert Richmeier, a landowner operating an irrigation well in the South Solomon River valley. His irrigation well had encountered salty water. An irrigation well belonging to an adjacent landowner, L. M. Paxson, had become salty in the fall of 1980. Oil has been produced in the area since 1952, and since 1962 secondary recovery by water flooding has been used. Upon investigation by the KDHE, it was discovered that the cause of the pollution was a saltwater injection well nearby, operated by Petro-Lewis. A casing profile caliper log was run by an operator-contractor under the direction of KDHE staff, which revealed numerous holes in the casing of the injection well. The producing formation, the Kansas City-Lansing, requires as much as 800 psi at the wellhead while injecting fluid to create a profitable enhanced oil recovery project. To remediate the contamination, the alluvial aquifer was pumped, and the initial chloride concentration of 6,000 mg/L was lowered to 600 to 700 mg/L in a year's time. Chloride contamination in some areas was lowered from 10,000 mg/L to near background levels. However, a contamination problem continues in the Paxson well, which shows chlorides in the range of 1,100 mg/L even though KDHE, through pumping, has tried to reduce the concentration. After attempts at repair, Petro-Lewis decided to plug the injection well.

Waste Analysis

Richmeier and Paxson wells showed a chloride concentration at over 6,000 mg/L and 4,700 mg/L, respectively, in 7/81. As wells were pumped, the chloride concentration decreased.

Comments

Comments in the Docket by the KCC (Bill Bryson) pertain to KS 06. KCC states that of the affected irrigation wells, one is "...back in service and the second is approaching near normal levels as it continues to be pumped." API states that Kansas received primacy for the UIC program in 1984.

Violation of State Regulations: No

Documentation

References for case cited: Richmeier Pollution Study, Kansas Department of Health and Environment, G. Blackburn and W. G. Bryson, 1983.

TX 55

State: Texas

Region: 7

County/Parish: Harris

City/Town: Not Applicable

Test of Proof: Administrative and Scientific

Description

In Texas, oil and gas producers operating near the Gulf Coast are permitted to discharge produced water into surface streams if they are found to be tidally affected. Along with the produced water, residual production chemicals and organic constituents may be discharged, including lead, zinc, chromium, barium, and water-soluble polycyclic aromatic hydrocarbons (PAHs). PAHs are known to accumulate in sediment, producing liver and lip tumors in catfish and affecting mixed function oxidise systems of mammals, rendering a reduced immune response. In 1984, a study conducted by the U.S. Fish and Wildlife Service of sediment in Tabb's Bay, which receives discharged produced water as well as discharges from upstream industry (i.e., discharges from ships in the Houston Ship Channel), indicated severe degradation of the environment by PAH contamination. Sediment was collected from within 100 yards of several tidal discharge points of oil field produced water. Analytical results of these sediments indicated severe degradation of the environment by PAH contamination. The study noted that sediments contained no benthic fauna, and because of wave action, the contaminants were continuously resuspended, allowing chronic exposure of contaminants to the water column. It is concluded by the U.S. Fish and Wildlife Service that shrimp, crabs, oysters, fish, and fish-eating birds in this location have the potential to be heavily contaminated with PAHs. While these discharges have to be within Texas Water Quality Standards, these standards are for conventional pollutants and do not consider the water-soluble components of oil that are in produced water such as PAHs.

Waste Analysis

Tabbs Bay (Galveston Bay) sediment analysis showed naphthalenes at 95 ppb, biphenyls at 120 ppb, phenanthrene at 105 ppb, anthracene at 74 ppb, pyrene at 150 ppb, chrysene at 122 ppb, fluoranthenes at 376 ppb, benzo-pyrene at 195 ppb, and perylene at 261 ppb.

Comments

NPDES permits have been applied for but not issued for these discharges on the Gulf Coast. The Texas Railroad Commission (TRC) issues permits for these discharges. The TRC disagrees as to the actual source of damage in this case.

Violation of State Regulations: No

Documentation

References for case cited: Letter from U.S. Department of the Interior, Fish and Wildlife Service, signed by H. Dale Hall, to Railroad Commission of Texas, discussing degradation of Tabb's Bay because of discharge of produced water in upstream estuaries; includes lab analysis for polycyclic aromatic hydrocarbons in Tabb's Bay sediment samples. Texas Railroad Commission Proposal for Decision on Petronilla Creek case documenting that something other than produced water is killing aquatic organisms in the creek. (Roy Spears, Texas Parks and Wildlife, did LC50 study on sunfish and sheepshead minnows using produced water and Arkansas Bay water. Produced water diluted to proper salinity caused mortality of 50 percent. (Seawater contains 19,000 ppm chlorides.)

TX 31

State: Texas

Region: 7

County/Parish: Galveston

City/Town: Galveston

Test of Proof: Scientific

Description

Produced water discharges contain a high ratio of calcium ions to magnesium ions. This high ratio of calcium to magnesium has been found by Texas Parks and Wildlife officials to be lethal to common Atlantic croaker, even when total salinity levels are within tolerable limits. In a bioassay study conducted by Texas Parks and Wildlife, this fish was exposed to various ratios of calcium to magnesium, and it was found that in 96-hour LC50 studies, mortality was 50 percent when exposed to calcium-magnesium ratios of 6:1, the natural ratio being 1:3. Nearly all of oil field produced water discharges on file with the Army Corps of Engineers in Galveston contain ratios exceeding the 6:1 ratio, known to cause mortality in Atlantic croaker as established by the LC50 test.

Waste Analysis

Analysis is in the form of a table showing calcium-magnesium ratios and numbers of surviving fish at 24-, 48-, and 96-hour intervals. At the natural ratio of 1:3, all fish survived the 96 hour test. At 7:1, half the fish died after 48 hours.

Comments

API comments in the Docket pertain to TX 31. API states that models show that "...rapid mixing in Bay waters results in no pollution to Bay waters as a whole from calcium ions or from the calcium/magnesium ratio."

Violation of State Regulations: No

Documentation

References for case cited: Toxic Effects of Calcium on the Atlantic Croaker: An Investigation of One Component of Oil Field Brine, by Kenneth N. Knudson and Charles E. Belaire, undated.

TX 29

State: Texas

Region: 7

County/Parish: Nueces

City/Town: Driscoll

Test of Proof: Administrative and Scientific

Description

For over 50 years, oil operators (including Texaco and Amoco) have been allowed to discharge produced water into Petronilla Creek, a supposedly tidally influenced creek. Discharge areas were as much as 20 miles inland and contained fresh water. In 1981, the pollution of Petronilla Creek from discharge of produced water became an issue when studies done by the Texas Parks and Wildlife and Texas Department of Water Resources documented the severe degradation of the water and damage to native fish and vegetation. All freshwater species of fish and vegetation were dead because of exposure to toxic constituents in discharge liquid. Portions of the creek were black or bright orange in color. Heavy oil slicks and oily slime were observable along discharge areas.

Impacts were observed in Baffin Bay, where the creek empties. Petronilla Creek is the only freshwater source for Baffin Bay, which is a nursery for many fish and shellfish in the Gulf of Mexico. Sediments in Baffin Bay show elevated levels of toxic constituents found in Petronilla Creek. For 5 years, the Texas Department of Water Resources and Texas Parks and Wildlife, along with environmental groups, worked to have the discharges stopped. In 1981, a hearing was held by the TRC. The conclusion of the hearing was that discharge of the produced water plus disposal of other trash by the public was degrading Petronilla Creek. The TRC initiated a joint committee (Texas Department of Water Resources, Texas Parks and Wildlife Department, and TRC) to establish the source of the trash, clean up trash from the creek, and conduct additional studies. After this work was completed, a second hearing was held in 1984. The creek was shown to contain high levels of chromium, barium, oil, grease, and EPA priority pollutants naphthalene and benzene. Oil operators stated that a no dumping order would put them out of business because oil production in this area is marginal. In 1986, the TRC ordered a halt to discharge of produced water into nontidal portions of Petronilla Creek.

Waste Analysis

A 1984 analysis of stream water indicated chloride at 40,700 ppm, chemical oxygen demand at 425 ppm, oil at 18 ppm, sulfates at 350 ppm, temperature at 120 degrees F., and arsenic at 14 ppm. Creek sediments revealed chromium at 9.6 ppm, barium at 1,900 ppm, oil and grease at 10,500 ppm, volatile solids at 48,700 ppm, and zinc at 150 ppm.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: The Effects of Brine Water Discharges on Petronilla Creek, Texas Parks and Wildlife Department, 1981. Texas Department of Water Resources interoffice memorandum documenting spills in Petronilla Creek from 1980 to 1983. The Influence of Oilfield Brine Water Discharges on Chemical and Biological Conditions in Petronilla Creek, by Frank Shipley, Texas Department of Water Resources, 1984. Letter from Dick Whittington, EPA, to Richard Lowerre, documenting absence of NPDES permits for discharge to Petronilla Creek. Final Order of TRC, banning discharge of produced water to Petronilla Creek, 6/23/86. Numerous letters, articles, legal documents, on Petronilla Creek case.

OK 08

State: Oklahoma

Region: 7

County/Parish: Beckham

City/Town: Elk City

Test of Proof: Legal and Scientific

Description

On November 20, 1981, the Michigan-Wisconsin Pipe Line Company began drilling an oil and gas well on the property of Ralph and Judy Walker. Drilling was completed on March 27, 1982. Unlined reserve pits were used at the drill site. After 2 months of drilling, the water well used by the Walkers became polluted with elevated levels of chloride and barium, (683 ppm and 1,750 ppb, respectively). The Walkers were forced to haul fresh water from Elk City for household use. The Walkers filed a complaint with the Oklahoma Corporation Commission (OCC), and an investigation was conducted. The Michigan-Wisconsin Pipe Line Co. was ordered to remove all drilling mud from the reserve pit.

In the end, the Walkers retained a private attorney and sued Michigan-Wisconsin for damages sustained because of migration of reserve pit fluids into the freshwater aquifer from which they drew their domestic water supply. The Walkers won their case and received an award of $50,000.

Waste Analysis

Analysis done on the Walker water well on March 29, 1982, indicated chloride at 683 mg/L and barium at 1,750 ug/L. Analysis prior to drilling of the oil and gas well showed chlorides at 10 mg/L.

Comments

API states that the Oklahoma Corporation Commission is in the process of developing regulations to prevent leaching of salt muds into ground water.

Violation of State Regulations: No

Documentation

References for case cited: Pretrial Order, Ralph Gail Walker and Judy Walker vs. Michigan-Wisconsin Pipe Line Company and Big Chief Drilling Company, U.S. District Court, Western District of Oklahoma, #CIV-82-1726-R. Direct Examination of Stephen G. McLin, Ph. D. Direct Examination of Robert Hall. Direct Examination of Laurence Alatshuler, M. D. Lab results from Walker water well.

OK 02

State: Oklahoma

Region: 7

County/Parish: McClain

City/Town: Stillwater

Test of Proof: Legal and Scientific

Description

In 1973, Horizon Oil and Gas drilled an oil well on the property of Dorothy Moore. As was the common practice, the reserve pit was dewatered, and the remaining mud was buried on site. In 1985-86, problems from the buried reserve pit waste began to appear. The reserve pit contents were seeping into a nearby creek and pond. The surrounding soil had very high chloride content as established by Dr. Billy Tucker, an agronomist and soil scientist. Extensive erosion around the reserve pit became evident, a common problem with high-salinity soil. Oil slicks were visible in the adjacent creek and pond. An irrigation well on the property was tested by Dr. Tucker and was found to have 3,000 ppm chlorides; however, no monitoring wells had been drilled to test the ground water prior to the drilling of the oil well and background levels of chlorides were not established.

Dorothy Moore has filed civil suit against the operator for damages sustained during the oil and gas drilling activity. The case is pending.

Waste Analysis

An extensive analysis of soil and water samples was performed by Dr. Billy Tucker. For soil, results indicated levels of total soluble salt at 1,630 ppm or "...63 times higher than normal and sufficiently high to reduce yield of even salt tolerant crops." Exchangeable sodium in soil was found at 72 percent, or 47,038 ppm. For water, total soluble salt levels were recorded at 51,810 ppm and chloride at 5,000 ppm. "Water of this quality is not recommended for crop irrigation".

Comments

API comments in Docket pertain to OK 02. API states that "...there is no evidence that there has been any seepage whatsoever into surface water." API states that there are no irrigation wells on Mrs. Moore's farm. Further, it states that erosion has been occurring for years and is the "...result of natural conditions coupled with the failure of Mrs. Moore to repair terraces to prevent or limit such erosion." API does not provide supporting documentation.

Violation of State Regulations: No

Documentation

References for case cited: Extensive soil and water analysis results interpreted by Dr. Billy Tucker, agronomist and soil scientist, Stillwater, Oklahoma. Correspondence and conversation with Randall Wood, private attorney, Stack and Barnes, Oklahoma City, Oklahoma.

OK 06

State: Oklahoma

Region: 7

County/Parish: Noble

City/Town: Perry

Test of Proof: Administrative, Legal, and Scientific

Description

The Devore #1, a saltwater injection well located on the property of Verl and Virginia Hentges, was drilled in 1947 as an exploratory well. Shortly afterwards, it was permitted by the Oklahoma Corporation Commission (OCC) as a saltwater injection well. The injection formation, the Layton, was known to be capable of accepting 80 barrels per hour at 150 psi. In 1984, George Kahn acquired the well and the OCC granted an exception to Rule 3-305, Operating Requirements for Enhanced Recovery Injection and Disposal Wells, and permitted the well to inject 2,000 barrels per day at 400 psi. Later in 1984, it appeared that there was saltwater migration from the intended injection zone of the Devore #1 to the surface.[2] The Hentges alleged that the migrating salt water had polluted the ground water used on their ranch. In addition, they alleged that the migrating salt water was finding its way to the surface and polluting Warren Creek, a freshwater stream used by downstream residents for domestic water. Salt water discharged to the surface had contaminated the soil and had caused vegetation kills. A report by the OCC concluded that "the Devore #1 salt water disposal well operations are responsible for the contaminant plume in the adjacent alluvium and streams." The OCC required that a workover be done on the well. The workover was completed, and the operator continued to dispose of salt water in the well. The Hentges then sought private legal assistance and filed a lawsuit against George Kahn, the operator, for

$300,000 in actual damages and $3,000,000 in punitive damages. The lawsuit is pending, scheduled for trial in October 1987.

Waste Analysis

Analyses done by OCC and Southwell Laboratory produced similar results. The OCC results showed the following: at monitor well #1, chlorides at 550 ppm; at well #3, chlorides at 113,600 ppm; at well #4; chlorides at 77,900 ppm; at the tributary of Warren Creek, chlorides at 93,000 ppm and at Warren Creek, chlorides at 77,550 ppm.

Comments

API states that the operator now believes old abandoned saltwater pits to be the source of contamination as the well now passes UIC tests. Comments by API in the Docket pertain to OK 06. API states that "...tests on the well [pressure test and tracer logs] indicate the injection well is not a source of salt water." API has not provided documentation with this statement.

Violation of State Regulations: No

Documentation

References for case cited: Remedial Action Plan for Aquifer Restoration within Section #2, Township 21 North, Range 2 West, Noble County, Oklahoma, by Stephen G. McLin, Ph. D. Surface Pollution at the De Vore #1 Saltwater Disposal Site, Oklahoma Corporation Commission, 1986. District Court of Noble County, Amended Petition, Verl E. Hentges and Virginia L. Hentges vs. George Kahn, #C-84-110, 7/25/85. Lab analysis records of De Vore well from Oklahoma Corporation Commission and Southwell Labs. Communication with Alan DeVore, plaintiffs' attorney.

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[2] Comments by API in the Docket pertain to OK 06. API states that "...tests on the well pressure test and tracer logs indicate the injection well is not a source of salt water." API has not provided documentation with this statement.

TX 21

State: Texas

Region: 7

County/Parish: Lavaca

City/Town: Speaks

Test of Proof: Administrative and Scientific

Description

On May 16, 1984, Esenjay Petroleum Co. had completed the L.W. Bing #1 well at a depth of 9,900 feet and had hired T&L Lease Service to clean up the drill site. During cleanup, the reserve pit, containing high-chromium drilling mud, was breached by T&L Lease Service, allowing drilling mud to flow into a tributary of Hardy Sandy Creek. The drilling mud was up to 24 inches deep along the north bank of Hardy Sandy. Drilling mud had been pushed into the trees and brush adjacent to the drill site. The spill was reported to the operator and the Texas Railroad Commission. The TRC ordered cleanup, which began on May 20.

Because of high levels of chromium contained in the drilling mud, warnings were issued by the Lavaca-Navidad River Authority to residents and landowners downstream of the spill as it represented a possible health hazard to cattle watering from the affected streams. The River Authority also advised against eating the fish from the affected waters because of the high chromium levels in the drilling mud.

Waste Analysis

Total chromium from samples from the streambed was recorded at 30.8 to 47.6 ppm and pH at 8.0 to 9.6.

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: Memorandum from Lavaca-Navidad River Authority documenting events of Esenjay reserve pit discharge, 6/27/84, signed by J. Henry Neason. Letter to TRC from Lavaca-Navidad River Authority thanking the TRC for taking action on the Esenjay case, "Thanks to your enforcement actions, we are slowly educating the operators in this area on how to work within the law." Agreed Order, Texas Railroad Commission, #2-83,043, 11/12/84, fining Esenjay $10,000 for deliberate discharge of drilling muds. Letter from U. S. EPA to TRC inviting TRC to attend meeting with Esenjay Petroleum to discuss discharge of reserve pit into Hardy Sandy Creek, 6/1/84, signed by Thomas G. Giesberg. Texas Railroad Commission spill report on Esenjay operations, 5/18/84.

TX 22

State: Texas

Region: 7

County/Parish: Live Oak

City/Town: Beeville

Test of Proof: Administrative and Scientific

Description

On September 15, 1983, TXO Production Company began drilling its Dunn Lease Well No. B2 in Live Oak County. On October 5, 1983, employees of TXO broke the reserve pit levee and began spreading drilling mud downhill from the site, towards the fence line of property owned by the Dunns. By

October 9, the mud had entered the draw that flows into two stock tanks on the Dunn property. On November 24 and 25, dead fish were observed in the stock tank. On December 17, Texas Parks and Wildlife documented over 700 fish killed in the stock tanks on the Dunn property. Despite repeated requests by the Dunns, TXO did not clean up the drilling mud and polluted water from the Dunn property.

Lab results from TRC and Texas Department of Health indicated that the spilled drilling mud was high in levels of arsenic, barium, chromium, lead, sulfates, other metals, and chlorides. In February 1984, the TRC stated that the stock tanks contained unacceptable levels of nitrogen, barium, chromium, and iron, and that the chemicals present were detrimental to both fish and livestock. (The Dunns water their cows at this same stock tank.) After further analysis, the TRC issued a memorandum stating that the fish had died because of a cold front moving through the area, in spite of the fact that the soil, sediment, and water in and around the stock pond contained harmful substances. Ultimately, TXO was fined $1,000 by the TRC, and TXO paid the Dunns a cash settlement for damages sustained.

Waste Analysis

Soil analysis revealed arsenic at 4.8 ppm, barium at 7,800 ppm, chromium at 17 ppm, lead at 18 ppm, and mercury at 0.04 ppm. Tank bottom analysis showed arsenic at 0.87 ppm, chromium at 12 ppm, and zinc at 23 ppm. Analysis performed on dead fish by the Texas Veterinary Medical Diagnostic Laboratory System stated that the fish died of oxygen depletion.

Comments

API states that the fish died from oxygen depletion of the water. The Texas Railroad Commission believes that the fish died from exposure to cold weather.

Violation of State Regulations: Yes

Documentation

References for case cited: Texas Railroad Commission Motion to Expand Scope of Hearing, #2-82,919, 6/29/84. Texas Railroad Commission Agreed Order, #2-82,919, 12/17/84. Analysis by Texas Veterinary Medical Diagnostic Laboratory System on dead fish in Dunn stock tank. Water and soil sample analysis from the Texas Railroad Commission. Water and soil samples from the Texas Department of Health. Letter from Wendell Taylor, TRC, to Jerry Mullican, TRC, stating that the fish kill was the result of cold weather, 7/13/84. Miscellaneous letters and memos.

WY 03

State: Wyoming

Region: 8

County/Parish: Campbell

City/Town: Rozet

Test of Proof: Administrative and Scientific

Description

Altex Oil Company and its predecessors have operated an oil production field for several decades South of Rozet, Wyoming. (Altex purchased the property in 1984.) An access road runs through the area, which, according to Wyoming Department of Environmental Quality (WDEQ), for years was used as a drainage for produced water from the oil field operations.

In August of 1985, an official with WDEQ collected soil samples from the road ditch to ascertain chloride levels because it had been observed that trees and vegetation along the road were dead or dying. WDEQ analysis of the samples showed chloride levels as high as 130,000 ppm. The road was chained off in October of 1985 to preclude any further illegal disposal of produced water.

Waste Analysis

Analysis done on soil along the ditch on the side of the roadbed and at the discharge point indicated chlorides ranging from 5,100 to 130,000 ppm.

Comments

Comments in the Docket from the Wyoming Oil and Gas Conservation Commission (WOGCC) (Mr. Don Basko) pertain to WY 03. WOGCC states that "...not all water from Altex Oil producing wells..." caused the contamination problem. Further, WOGCC states that "Illegal dumping, as well as a flow line break the previous winter, had caused a high level of chloride in the soil which probably contributed to the sagebrush and conttonwood trees dying."

Violation of State Regulations: Yes

Documentation

References for case cited: Analysis of site by the Wyoming Department of Environmental Quality (WDEQ), Quality Division Laboratory, File #ej52179, 12/6/85. Photographs of dead and dying cottonwood trees and sagebrush in and around site. Conversation with WDEQ officials.

WY 01

State: Wyoming

Region: 8

County/Parish: Laramie

City/Town: Cheyenne

Test of Proof: Administrative, Legal, and Scientific

Description

In early October 1985, Cities Service Oil Company had completed drilling at a site northeast of Cheyenne on Highway 85. The drilling contractor, Z&S Oil Construction Company, was suspected of illegally disposing of drilling fluids at a site over a mile away on the Pole Creek Ranch. An employee of Z&S had given an anonymous tip to a County detective. A stake-out of the illegal operation was made with law enforcement and WDEQ personnel. Stake-out personnel took samples and photos of the reserve pit and the dump site. During the stake-out, vacuum trucks were witnessed draining reserve pit contents down a slope and into a small pond on the Pole Creek Ranch. After sufficient evidence had been gathered, arrests were made by Wyoming law enforcement personnel, and the trucks were impounded. The State sued Z&S and won a total of $10,000.

Waste Analysis

Analysis done on samples from the reserve pit and from the dump site showed that reserve pit mud contained aluminum at 20,591 ppm, arsenic at 4.06 ppm, barium at 144 ppm, chromium at 16.5 ppm, copper at 8.2 ppm, iron at 19,520 ppm, lead at 84 ppm, manganese at 108 ppm, and zinc at 129 ppm.

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: WDEQ memorandum documenting chronology of events leading to arrest of Z&S employees and owners. Lab analysis of reserve pit mud and effluent, and mud and effluent found at dump site. Consent decree from District Court of First Judicial District, Laramie County, Wyoming, docket #108-493, The People of the State of Wyoming vs. Z&S Construction Company. Photographs of vacuum trucks dumping at Pole Creek Ranch.

WY 05

State: Wyoming

Region: 8

County: Big Horn

City/Town: Byron

Test of Proof: Administrative, Legal, and Scientific

Description

During the week of April 8, 1985, field personnel at the Byron/Garland field operated by Marathon Oil Company were cleaning up a storage yard used to store drums of oil field chemicals. Drums containing discarded production chemicals were punctured by the field employees and allowed to drain into a ditch adjacent to the yard. Approximately 200 drums containing 420 gallons of fluid were drained into the trench. The chemicals were demulsifiers, reverse demulsifiers, scale and corrosion inhibitors, and surfactants. Broken transformers containing PCBs were leaking into soil in a nearby area. Upon discovery of the condition of the yard, Wyoming Department of Environmental Quality ordered Marathon to begin cleanup procedures. At the request of the WDEQ, ground-water monitors were installed, and monitoring of nearby Arnoldus Lake was begun. The State filed a civil suit against Marathon and won a $5,000 fine and $3,006 in expenses for lab work.

Waste Analysis

Analysis was done on volatile and semivolatile compounds in the soil. Compounds found include methylene chloride, 390 mg/kg; acetone, 250 mg/kg; vinyl acetate, 720 mg/kg; ethylbenzene, 220 mg/kg; xylenes, 1,300 mg/kg; naphthalene, 1,500 mg/kg; 2/ methylnaphthalene, 3,800 mg/kg; phenanthrene, 80 mg/kg; toluene, 205 mg/kg; and pyrene, 50 mg/kg.

Comments
API states that the operator, thinking the drums had to be empty before transport offsite, turned the drums upside down and drained 420 gallons of chemicals into the trench.

Violation of State Regulations: Yes

Documentation
References for case cited: Summary of Byron-Garland case by Marathon employee J. C. Fowler. List of drums, contents, and field uses. Cross-section of disposal trench area. Several sets of lab analyses. Map of Garland field disposal yard. Newspaper articles on incident. District court consent decree, The People of the State of Wyoming vs. Marathon Oil Company, #108-87.

WY 07

State: Wyoming

Region: 8

County/Parish: Fremont

City/Town: Lander

Test of Proof: Scientific

Description
A study was undertaken by the Columbia National Fisheries Research Laboratory of the U. S. Fish and Wildlife Service to determine the effect of continuous discharge of low-level oil effluent into a stream and the resulting effect on the aquatic community in the stream. The discharges to the stream contained 5.6 mg/L total hydrocarbons. Total hydrocarbons in the receiving sediment were 979 mg/L to 2,515 mg/L. During the study, samples were taken upstream and downstream from the discharge. Species

diversity and community structure were studied. Water analysis was done on upstream and downstream samples. The study found a decrease in species diversity of the macrobenthos community (fish) downstream from the discharge, further characterized by total elimination of some species and drastic alteration of community structure. The study found that the downstream community was characterized by only one dominant species, while the upstream community was dominated by three species. Total hydrocarbon concentrations in water and sediment increased 40 to 55 fold downstream from the discharge of produced water. The authors of the study stated that "...based on our findings, the fisheries and aquatic resources would be protected if discharge of oil into fresh water were regulated to prevent concentrations in receiving streams/ water and sediment that would alter structure of macrobenthos communities."

Waste Analysis

Analysis indicated the following results: total oil in the effluent was 5.6 mg/L, well below the permitted level of 10 mg/L; total oil in the sediments was 2,515 ppm, at the station furthest downstream; receiving stream concentrations were 46 to 85 ppb; naphthalenes, cadmium, chromium, copper, lead, and zinc were detected at elevated levels in the stream and sediment; and species diversity indexes were characteristic of moderately polluted habitats.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Petroleum Hydrocarbon Concentrations in a Salmonid Stream Contaminated by Oil Field Discharge Water and Effects on the Macrobenthos Community, by D. F. Woodward and R. G. Riley, U.S. Department of the Interior, Fish and Wildlife Service, Columbia National Fisheries Research Laboratory, Jackson, Wyoming, 1980; submitted to Transactions of the American Fisheries Society.

NM 02

State: New Mexico

Region: 9

County/Parish: San Juan

City/Town: Shiprock

Test of Proof: Scientific

Description

In July 1985, a study was undertaken in the Duncan Oil Field in the San Juan Basin by faculty members in the Department of Chemistry at New Mexico State University, to analyze the potential for unlined produced water pit contents, including hydrocarbons and aromatic hydrocarbons, to migrate into the ground water. The oil field is situated in a flood plain of the San Juan River. The site chosen for investigation by the study group was similar to at least 1500 other nearby production sites in the flood plain. The study group dug test pits around the disposal pit on the chosen site. These test pits were placed abovegradient and downgradient of the disposal pit, at 25-and 50-meter intervals. A total of nine test pits were dug to a depth of 2 meters, and soil and ground-water samples were obtained from each test pit. Upon analysis, the study group found volatile aromatic hydrocarbons were present in both the soil and water samples of test pits downgradient, demonstrating migration of unlined produced water pit contents into the ground water.

Environmental impact was summarized by the study group as contamination of shallow ground water with produced water pit contents due to leaching from an unlined produced water disposal pit. Benzene was found in concentrations of 0.10 ppb. New Mexico Water Quality Control Commission standard is 10 ppb. Concentrations of ethylbenzene, xylenes, and larger hydrocarbon molecules were found. No contamination was found in test pits placed abovegradient from the disposal pit. Physical signs of contamination were also present, downgradient from the disposal pit, including black, oily staining of sands above the water table and black, oily film on the water itself. Hydrocarbon odor was also present.

Waste Analysis

Extensive and complex analysis of water and soil samples for volatile organic compounds indicated estimated concentrations of benzene, 0.1 ppb, and toluene, 0.3 ppm in test pits, as well as benzene at 21 ppb and 160 ppb in waste pit water and produced water, respectively. The analysis also contains proof of extensive mobility of these compounds in the ground water and surrounding sandy soil.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Hydrocarbons and Aromatic Hydrocarbons in Groundwater Surrounding an Earthen Waste Disposal Pit for Produced Water in the Duncan Oil Field of New Mexico, by G. A. Eiceman, J.T. McConnon, Masud Zaman, Chris Shuey, and Douglas Earp, 9/16/85. Polycyclic Aromatic Hydrocarbons in Soil at Groundwater Level Near an Earthen Pit for Produced Water in the Duncan Oil Field, by B. Davani, K. Lindley, and G.A. Eiceman, 1986. New Mexico Oil Conservation Commission hearing to define vulnerable aquifers, comments on the hearing record by Intervenor Chris Shuey, Case No. 8224.

NM 05

State: New Mexico

Region: 9

County: San Juan

City/Town: Farmington

Test of Proof: Administrative and Scientific

Description

Lee Acres "modified" landfill (meaning refuse is covered weekly instead of daily as is done in a "sanitary" landfill) is located 4.5 miles east-southeast of Farmington, New Mexico. It is owned by the U.S. Bureau of Land Management (BLM). The landfill is approximately 60 acres in size and includes four unlined liquid-waste lagoons or pits, three of which were actively used. Since 1981, a variety of liquid wastes associated with the oil and gas industry have been disposed of in the lagoons. The predominant portion of liquid wastes disposed of in the lagoons was produced water, which is known to contain aromatic volatile organic compounds (VOCs). According to the New Mexico Department of Health and Environment, Environmental Improvement Division, 75 to 90 percent of the produced water disposed of in the lagoons originated from Federal and Indian oil and gas leases managed by BLM. Water produced on these leases was hauled from as far away as Nageezi, which is 40 miles from the Lee Acres site. Disposal of produced water in these unlined pits was, according to New Mexico State officials, in direct violation of BLM's rule NTL-2B, which prohibits, without prior approval, disposal of produced waters into unlined pits, originating on Federally owned leases. The Department of the Interior states that disposal in the lagoons was "...specifically authorized by the State of New Mexico for disposal of produced water." The State of New Mexico states that "There is no truth whatsoever to the assertion that the landfill lagoons were specifically authorized by the State of New Mexico for disposal of produced water." Use of the pits ceased on 4/19/85; 8,800 cubic yards of waste were disposed of prior to closure.

New Mexico's Environmental Improvement Division (NMEID) asserts that leachate from the unlined waste lagoons that contain oil and gas wastes has contributed to the contamination of several water wells in the Lee Acres housing subdivision located downgradient from the lagoons and downgradient from a refinery operated by Giant Refining Company, located nearby. NMEID has on file a soil gas survey that documents extensive contamination with chlorinated VOCs at the landfill site. High levels of sodium, chlorides, lead, chromium, benzene, toluene, xylenes, chloroethane, and trichloroethylene were found in the waste lagoons. An electromagnetic terrain survey of the Lee Acres landfill site and surrounding area, conducted by NMEID, located a plume of contaminated ground water extending from the landfill. This plume runs into a plume of contamination known to exist, emanating from the refinery. The plumes have become mixed and are the source of contamination of the ground water serving the Lee Acres housing subdivision. One domestic well was sampled extensively by NMEID and was found to contain extremely high levels of chlorides and elevated levels of chlorinated VOCs, including trichloroethane. (Department of the Interior (DOI) states that it is unaware of any violations of New Mexico ground-water standards involved in this case. New Mexico states that State ground-water standards for chloride, total dissolved solids, benzene, xylenes, 1,1-dichloroethane, and ethylene dichloride have been violated as a result of the plume of contamination. In addition, the EPA Safe Drinking Water Standard for trichloroethylene has been violated.) New Mexico State officials state that "The landfill appears to be the principal source of chloride, total dissolved solids and most chlorinated VOCs, while the refinery appears to be the principal source of aromatic VOCs and ethylene dichloride."

During the period after disposal operations ceased and before the site was closed, access to the lagoons was essentially unrestricted. While NMEID believes that it is possible that non-oil and gas wastes illegally disposed of during this period may have contributed to the documented contamination, the primary source of ground-water contamination appears to be from oil and gas wastes.

The State has ordered BLM to provide public water to residents affected by the contamination, develop a ground-water monitoring system, and investigate types of drilling, drilling procedures, and well construction methods that generated the waste accepted by the landfill. BLM submitted a motion-to-stay the order so as to include Giant Refining Company and El Paso Natural Gas in cleanup operations. The motion was denied. The case went into litigation. According to State officials, "The State of New Mexico agreed to dismiss its lawsuit only after the Bureau of Land Management agreed to conduct a somewhat detailed hydrogeologic investigation in a reasonably expeditious period of time. The lawsuit was not dismissed because of lack of evidence of contamination emanating from the landfill." While it is true that past refinery operations also have contaminated ground water, it should be noted that the refinery company, unlike the Bureau of Land Management, has completed an extensive hydrogeologic investigation and has already implemented both containment and cleanup measures.

Waste Analysis

Extensive water analysis has been done on the pits and the contaminated water wells. High levels of sodium, chlorides, lead, chromium, benzene, toluene, xylenes, chloroethane, and trichloroethylene were found in the pits. High levels of chlorides and VOCs were found in a downgradient monitoring well. Complete analysis is in the file. One domestic well was sampled extensively and found to contain extremely high levels of chloride and elevated levels of chlorinated VOC's, including trichloroethane. Except for benzene, the contaminants found in this well (Reynold's well) are not characteristic of the contaminats generated by the nearby refinery.

Comments

In a letter dated 8/20/87, Giant Refining Company states that "Benzene, toluene, and xylenes are naturally occurring compounds in crude oil, and are consequently in high concentrations in the produced water associated with that crude oil. The only gasoline additive used by Giant that has been found in the water of a residential well is DCA [ethylene dichloride], which has also been found in the landfill plume." Giant also notes that the refinery leaks in the last 2 years resulted in less than 30,000 gallons of diesel being released rather than the 100,000 gallons stated by Michael Poling in his letter to EPA of 8/11/87.

Comments in the Docket from BLM and the State of New Mexico pertain to NM 05. BLM states that the refinery upgradient from the subdivision is responsible for the contamination because of their "...extremely sloppy housekeeping practices..." which resulted in the loss of "...hundreds of thousands of gallons of refined product through leaks in their underground piping system." The Department of the Interior states that "There is, in fact, mounting evidence that the landfill and lagoons may have contributed little to the residential well contamination in the subdivisions." DOI states "...we strongly recommend that this case be deleted from the Damage Cases [Report to Congress]." New Mexico states that "EID [Environmental Improvement Division] strongly believes that the Lee Acres Landfill has caused serious ground water contamination and is well worth inclusion in the Oil and Gas Damage Cases chapter of your [EPA] Report to Congress on Oil, Gas and Geothermal Wastes."

Violation of State Regulations: No

Documentation

References for case cited: State of New Mexico Administrative Order No. 1005; contains water analysis for open pits, monitor wells, and impacted domestic wells. Motion-to-stay Order No. 1005. Denial of motion to stay. Newspaper articles. Southwest Research and Information Center, Response to Hearing before Water Quality Control Commission, 12/2/86. Letter to Dan Derkics, EPA from Michael Poling, Department of the Interior, refuting Lee Acres damage case, 8/11/87. Letter to Dan Derkics, EPA from Michael J. Burkhart, NMEID, refuting DOI letter of 8/11/87, dated 8/18/87. Letter to Dan Derkics, EPA, from Giant Refining Company, 8/20/87.

NM 01

State: New Mexico

Region: 9

County/Parish: Lea

City/Town: Caprock

Test of Proof: Legal and Scientific

Description

A saltwater injection well, the BO-3, operated by Texaco, is used for produced water disposal for the Moore-Devonian oil field in southeastern New Mexico. Injection occurs at about 10,000 feet. The Ogallala aquifer, overlying the oil production formation, is the sole source of potable ground water in much of southeastern New Mexico. Dr. Daniel B. Stephens, Associate Professor of Hydrology at the New Mexico Institute of Mining and Technology, concluded that injection well BO-3 has contributed to a saltwater plume of contamination in the Ogallala aquifer. The plume is nearly 1 mile long and contains chloride concentrations of up to 26,000 ppm.

A local rancher sustained damage to crops after irrigating with water contaminated by this saltwater plume. In 1973, an irrigation well was completed satisfactorily on the ranch of Mr. Paul Hamilton, and, in 1977, the well began producing water with chlorides of 1,200 ppm.
Mr. Hamilton's crops were severely damaged, resulting in heavy economic losses, and his farm property was foreclosed. There is no evidence of crop damage from irrigation prior to 1977. Mr. Hamilton initiated a private law suit against Texaco for damages sustained to his ranch. Texaco argued that the saltwater plume was the result of leachate of produced water from unlined produced water disposal pits, now banned in the area. Dr. Stephens proved that if old pits in the vicinity, previously used for saltwater disposal, had caused the contamination, high chloride levels would have been detected in the irrigation well prior to 1977. Dr. Stephens also demonstrated that the BO-3 injection well had leaked some 20 million gallons of produced water into the fresh

ground water, causing chloride contamination of the Ogallala aquifer from which Mr. Hamilton drew his irrigation water. Based on this evidence, a jury awarded Mr. Hamilton a cash settlement from Texaco for damages sustained both by the leaking injection well and by the abandoned disposal pits. The well has had workovers and additional pressure tests since 1978. The well is still in operation, in compliance with UIC regulations.

Waste Analysis

A hydrogeologic configuration illustrated a plume of contamination, and water analysis showed chlorides as high as 25,000 ppm in the aquifer around the BO-3 injection well. Analysis of the irrigation well indicated chlorides at 1,200 ppm.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Oil-Field Brine Contamination - A Case Study, Lea Co. New Mexico, from Selected Papers on Water Quality and Pollution in New Mexico - 1984; proceedings of a symposium, New Mexico Bureau of Mines and Resources.

CA 21

State: California

Region: 10

County/Parish: Kern

City/Town: Taft

Test of Proof: Scientific

Description

For the purposes of this study conducted by Bean/Logan Consulting Geologists, ground water in the study area was categorized according to geotype and compared to produced water in sumps that came from production zones. Research was conducted on sumps in Cymric Valley, McKittrick Valley, Midway Valley, Elk Hills, Buena Vista Hills, and Buena Vista Valley production fields. While this recent research was not investigating ground-water damages per se, the study suggests obvious potential for damages relating to the ground water. The hydrogeologic analysis prepared for the California State Water Resources Control Board concludes that about 570,000 tons of salt from produced water were deposited in 1981 and that a total of 14.8 million tons have been deposited since 1900. The California Water Resources Board suspects that a portion of the salt has percolated into the ground water and has degraded it. In addition to suspected degradation of ground water, officers of the California Department of Fish and Game often find birds and animals entrapped in the oily deposits in the affected ephemeral streams. Exposure to the oily deposits often proves to be fatal to these birds and animals.

Waste Analysis

See: CA 8. Ground water in the study area has been categorized according to geotypes and compared to produced waters in sumps that came from production zones. Research found that sumps in Cymric, McKittrick, and Midway Valleys, Elk Hills and Buena Vista Hills, and Buena Vista Valley fields were responsible in part for ground-water brine. Table 22 in the Westside Groundwater Study, which analyzed "feed water" (brines) to sumps, indicated the following results: chlorides at 729 to 10,726 ppm, conductivity of 4,500 to 28,260 uhos; total dissolved solids at 3,258 to 20,488 ppm, and boron at 5.2 to 19.2 ppm.

Comments

API states that the California Regional Water Quality Board and EPA are presently deciding whether to promulgate additional permit requirements under the Clean Water Act and NPDES.

Violation of State Regulations: No

Documentation

References for case cited: Lower Westside Water Quality Investigation Kern County and Lower Westside Water Quality Investigation Kern County: Supplementary Report, Bean/Logan Consulting Geologists, 11/83; prepared for Califormia State Water Resources Control Board. Westside Groundwater Study, Michael R. Rector, Inc., 11/83; prepared for Western Oil and Gas Association.

CA 08

State: California

Region: 10

County/Parish: Kern

City/Town: Bakersfield

Test of Proof: Scientific

Description

Produced water from the Crocker Canyon area flows downstream to where it is diverted into Valley Waste Disposal's large unlined evaporation/percolation sumps for oil recovery (cooperatively operated by local oil producers). In one instance, discovery by California Fish and Game officials of a significant spill was made over a month after it occurred. According to the California State Water Quality Board, the incident was probably caused by heavy rainfall, as a consequence of which the volume of rain and waste exceeded the containment capacity of the disposal facility. The sumps became eroded, allowing oily waste to flow down the valley and into a wildlife habitat occupied by several endangered species including blunt-nosed leopard lizards, San Joaquin kit foxes, and giant kangaroo rats.

According to the State's report, there were 116 known wildlife losses including 11 giant kangaroo rats. The count of dead animals was estimated at only 20 percent of the actual number of animals destroyed because of the delay in finding the spill, allowing poisoned animals to leave the area before dying. Vegetation was covered with waste throughout the spill area. The California Department of Fish and Game does not believe this to be an isolated incident. The California Water Resources Control Board, during its investigation of the incident, noted "...deposits of older accumulated oil, thereby indicating that the same channel had been used for wastewater disposal conveyance in the past prior to the recent discharge. Cleanup activities conducted later revealed that buildup of older oil was significant." The companies implicated in this incident were fined $100,000 and were required to clean up the area. The companies denied responsibility for the discharge.

Waste Analysis

A description by a Department of Fish and Game official based on a visual inspection indicated that the waste was produced water and oil from the facilities listed above.

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: Report of Oil Spill in Buena Vista Valley, by Mike Glinzak, California Division of Oil and Gas (DOG), 3/6/86; map of site and photos accompany the report. Letters to Sun Exploration and Production Co. from DOG, 3/12 and 3/31/86. Newspaper articles in Bakersfield Californian, 3/8/86, 3/11/86, and undated. California Water Quality Control Board, Administrative Civil Liability Complaint #ACL-016, 8/8/86. California Water Quality Control Board, internal memoranda, Smith to Pfister concerning cleanup of site, 5/27/86; Smith to Nevins concerning description of damage and investigation, including map, 8/12/86. California Department of Fish and Game, Dead Endangered Species in a California Oil Spill, by Capt. E.A Simons and Lt. M. Akin, undated. Fact Sheets: Buena Vista Creek Oil Spill, Kern County, 3/7/86, and Mammals Occurring on Elk Hills and Buena Vista Hills, undated. Letter from Lt. Akin to EPA contractor, 2/24/87.

AK 06

State: Alaska

Region: 11

County/Parish: Prudhoe Bay

City/Town: Not Applicable

Test of Proof: Scientific

Description

In 1983, a study of the effects of reserve pit discharges on water quality and the macroinvertebrate community of tundra ponds was undertaken by the U. S. Fish and Wildlife Service in the Prudhoe Bay oil production area of the North Slope. Discharge to the tundra ponds is a common disposal method for reserve pit fluid in this area. The study shows a clear difference in water quality and biological measures among reserve pits, ponds receiving discharges from reserve pits (receiving ponds), distant ponds affected by discharges through surface water flow, and control ponds not affected by discharges. Ponds directly receiving discharges had significantly greater concentrations of chromium, arsenic, cadmium, nickel, and barium than did control ponds, and distant ponds showed significantly higher levels of chromium than did control ponds. Chromium levels in reserve pits and in ponds adjacent to drill sites may have exceeded EPA chronic toxicity criteria for protection of aquatic life.

Waste Analysis

Analysis was done on all parameters for all pits and ponds. Statistical tests were performed on data to show the statistical significance of the results. Conductivity was as high as 9,500 umhos/cm; lead, 0.093 mg/L; copper, 0.029mg/L; zinc, 0.33 mg/L; cadmium, 0.0009mg/L; chromium, 0.21 mg/L; arsenic, 0.05 mg/L; nickel, 0.17 mg/L; aluminum, 97 mg/L; and barium, 4.4 mg/L. Results indicated statistically sifgnificant differences in biological measures and water quality between pits, receiving ponds, and distant ponds.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: The Effects of Prudhoe Bay Reserve Pit Fluids on the Water Quality and Macroinvertebrates of Tundra Ponds (Draft report), by Robin L. West and Elaine Snyder-Conn, Fairbanks Fish and Wildlife Enhancement Office, U.S. Fish and Wildlife Service, Fairbanks, Alaska, 10/8/86.

AK 07

State: Alaska

Region: 11

County/Parish: Prudhoe Bay

City/Town: Not Applicable

Test of Proof: Scientific

Description

In the summer of 1985, the U. S. Fish and Wildlife Service developed a field method to evaluate toxicity of reserve pit fluids discharged into tundra wetlands at Prudhoe Bay, Alaska. Results of the study document acute toxicity effects of reserve pit fluids on Daphnia. Acute toxicity in Daphnia was observed after 96 hours of exposure to liquid in five reserve pits. Daphnia exposed to liquid in receiving ponds also had significantly higher death/immobilization than did Daphnia exposed to liquid in control ponds after 96 hours. At Drill Site 1, after 96 hours, 100 percent of the Daphnia introduced to the reserve pit had been immobilized or were dead, as compared to a control pond that showed less than 5 percent immobilized or dead after 96 hours. At Drill Site 12, 80 percent of the Daphnia exposed to the reserve pit liquid were dead or immobilized after 96 hours and less than 1 percent of the Daphnia exposed to the control pond were dead or immobilized.

Waste Analysis

The results of the bioassays described above constitute the only analyses available on environmental damage for this case.

Comments

API comments in the Docket pertain to AK 07. API discusses the relevance of the Daphnia study to the damage cases.

Violation of State Regulations: No

Documentation

References for case cited: An In Situ Acute Toxicity Test with Daphnia: A Promising Screening Tool for Field Biologists? by Elaine Snyder-Conn, U.S. Fish and Wildlife Service, Fish and Wildlife Enhancement, Fairbanks, Alaska, 1985.

AK 08

State: Alaska

Region: 11

County/Parish: Prudhoe Bay

City/Town: Not Applicable

Test of Proof: Scientific

Description

In June 1985, five drill sites and three control sites were chosen for studying the effects of drilling fluids and their discharge on fish and waterfowl habitat on the North Slope of Alaska. Bioaccumulation analysis was done on fish tissue using water samples collected from the reserve pits. Fecundity and growth were reduced in daphnids exposed for 42 days to liquid composed of 2.5 percent and 25 percent drilling fluid from the selected drill sites. Bioaccumulation of barium, titanium, iron, copper, and molybdenum was documented in fish exposed to drilling fluids for as little as 96 hours.

Waste Analysis

Highest readings found in water samples were: conductivity, 4,200 umhos/cm; bromine, 54 mg/L; aluminum, 0.853 mg/L; arsenic, 0.177 mg/L; boron, 2.33 mg/L; cadmium, 0.005 mg/L; chromium, 0.493 mg/L; copper, 0.095 mg/L; iron, 1.180 mg/L; magnesium, 14.9 mg/L; manganese, 0.808 mg/L; phosphorous, 0.226 mg/L; lead, 0.06 mg/L; and titanium, 0.139 mg/L. Sediment analysis highs were: aluminum, 21,000 mg/kg; arsenic, 138 mg/kg; barium, 7,380 mg/kg; cadmium, 6.0 mg/kg; cobalt, 17 mg/kg; chromium, 792 mg/kg; copper, 1,780 mg/kg; manganese, 1,930 mg/kg; lead, 1,300 mg/kg; and titanium, 37 mg/kg.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Effects of Oil Drilling Fluids and Their Discharge on Fish and Waterfowl Habitat in Alaska, U.S. Fish and Wildlife Service, Columbia National Fishery Research Laboratory, Jackson Field Station, Jackson, Wyoming, February 1986.

AK 12

State: Alaska

Region: II

County/Parish: National Petroleum Reserve-Alaska

City/Town: Not Applicable

Test of Proof: Scientific

Description

The Awuna Test Well No. 1, which is 11,200 feet deep, is in the National Petroleum Reserve in Alaska (NPRA) and was a site selected for cleanup of the NPRA by the U.S. Geological Survey in 1984. The site is in the northern foothills of the Brooks Range. The well was spud on February 29, 1980, and operations were completed on April 20, 1981. A side of the reserve pit berm washed out into the tundra during spring breakup, allowing for reserve pit fluid to flow onto the tundra. As documented by the U.S. Geological Survey (USGS) cleanup team, high levels of chromium, oil, and grease have leached into the soil downgradient from the pit. Chromium was found at 2.2 to 3.0 mg/kg dry weight. The high levels of oil and grease may be from the use of Arctic Pack (85 percent diesel fuel) at the well over the winter of 1980. The cleanup team noted that the downslope soils were discolored and putrefied, particularly in the upper layers. The pad is located in a runoff area allowing for erosion of pad and pit into surrounding tundra. A vegetation kill area caused by reserve pit fluid exposure is approximately equal to half an acre. Areas of the drill pad may remain barren for many years because of contamination of soil with salt and hydrocarbons. The well site is in a caribou calving area.

Waste Analysis

Analysis done on reserve pit mud, fluid, and soil around the pad and pits indicated mud with a pH of 8.1, chlorides at 10,300 ppm, chemical oxygen demand at 140,000, iron at 2,900 ppm, oil and grease at 7,560 ppm, and chromium at 230 ppm. Soil 50 feet from the pit showed a pH of 6.8, chlorides at 86.2 ppm, chromium at 3.0 ppm, and oil and grease at 10,000 ppm.

Comments

API states that exploratory reserve pits must now be closed 1 year after cessation of drilling operations. EPA notes that it is important to distinguish between exploratory and production reserve pits. Production reserve pits are permanent structures that remain open as long as the well or group of wells is producing.

Violation of State Regulations: No

Documentation

References for case cited: Final Wellsite Cleanup on National Petroleum Reserve - Alaska, USGS, July 1986.

AK 10

State: Alaska

Region: 11

County/Parish: Prudhoe Bay

City/Town: Not Applicable

Test of Proof: Administrative and Scientific

Description

North Slope Salvage, Inc. (NSSI) operated a salvage business in Prudhoe Bay during 1982 and 1983. During this time, NSSI accepted delivery of various discarded materials from oil production companies on the North Slope, including more than 14,000 fifty-five gallon drums, 900 of which were full or held more than residual amounts of oil and chemicals used in the development and recovery of oil. The drums were stockpiled and managed by NSSI in a manner that allowed the discharge of hazardous substances. While the NSSI site may have stored chemicals and wastes from other operations that supported oil and gas exploration and production (e.g., vehicle maintenance materials), such storage would have constituted a very small percentage of NSSI's total inventory.

The situation was discovered by the Alaska Department of Environmental Conservation (ADEC) in June 1983. At this time, the State of Alaska requested Federal enforcement, but Federal action was never taken. An inadequate cleanup effort was mounted by NSSI after confrontation by ADEC. To preclude further discharges of hazardous substances, ARCO and Sohio paid for the cleanup because they were the primary contributors to the site. Cleanup was completed on August 5, 1983, after 58,000 gallons of chemicals and water were recovered. It is unknown how much of the hazardous substances were carried into the tundra. The discharge consisted of oil and a variety of organic substances known to be toxic, carcinogenic, or mutagenic, or suspected of being carcinogenic or mutagenic.

Waste Analysis

Samples were taken from many locations at the site, both directly from drums and from soil and water. GC/MS was done on each sample to define organic compounds present. Analysis indicated pH at 13.8, benzene at 20.0 ug/L, xylene at 67.0 ug/L, and toluene at 190 ug/L. Other results are in the file.

Comments

Alaska Department of Environmental Conservation (ADEC) states that this case "...is an example of how the oil industry inappropriately considered the limits of the exemption [under RCRA Section 3001]."

Violation of State Regulations: No

Documentation

References for case cited: Report on the Occurrence, Discovery, and Cleanup of an Oil and Hazardous Substances Discharge at Lease Tract 57, Prudhoe Bay, Alaska, by Jeff Mach - ADEC, 1984. Letter to Dan Derkics, EPA, from Stan Hungerford, ADEC, 8/4/87.

AK 03

State: Alaska

Region: 11

County/Parish: Kenai Peninsula

City/town: Sterling

Test of Proof: Administrative and Scientific

Description

Operators of the Sterling Special Waste site have had a long history of substandard monitoring, having failed during 1977 and 1978 to carry out any well sampling and otherwise having performed only irregular sampling. This was in violation of ADEC permit requirements to perform quarterly reports of water quality samples from the monitoring wells. An internal DEC memo (L.G. Elphic to R.T. Williams, 2/25/76) noted "...we must not forget...that this is the State's first sanctioned hazardous waste site and as such must receive close observation during its initial operating period."

A permit for the site was reissued by ADEC in 1979 despite knowledge by ADEC of lack of effective ground-water monitoring. In July of 1980, ADEC Engineer R. Williams visited the site and filed a report noting that the "...operation appears completely out of control." Monitoring well samples were analyzed by ADEC at this time and found to be in excess of drinking water standards for iron, lead, cadmium, copper, zinc, arsenic, phenol, and oil and grease. One private water well in the vacinity showed 0.4 ppb 1,1,1-trichloroethane. The Sterling School well showed 2.1 ug/L mercury. Subsequent tests show mercury concentration below detection limits--0.001 mg/kg. Both contamination incidents are alleged to be caused by the Sterling Special Waste Site. Allegations are unconfirmed by the ADEC.

Waste Analysis

Typical mud contents include barium, chromium, cadmium, phenols, diesel oils, etc. (See AK 02.) Specific analysis of the contents of the Sterling Site showed the following: ethlybenzene, 0.6 mg/L; toluene, 5.6 mg/L; iron, 184 mg/L; lead, 0.88 mg/L; zinc, 28 mg/L; cadmium, 0.08 mg/L; and copper, 2.3 mg/L.

Comments

The term "hazardous waste site" as used in this memo does not refer to a "RCRA Subtitle C hazardous waste site."

Violation of State Regulations: Yes

Documentation

References for case cited: Dames and Moore well monitoring report, showing elevated metals referenced above, October 1976. Dowling Rice & Associates monitoring results, 1/15/80, and Mar Enterprises monitoring results, September 1980, provided by Walt Pederson, showing elevated levels of metals, oil, and grease in ground water. Detailed letter from Eric Meyers to Glen Aikens, Deputy Commissioner, ADEC, recounting permit history of site and failure to conduct proper monitoring, 1/22/82. Testimony and transcripts from Walt Pederson on public forums complaining about damage to drinking water and mismanagement of site. Transcripts of waste logs of site from 9/1/79 to 8/20/84, indicating only 264,436 bbl of muds received, during a period that should have generated much more waste. Letter from Howard Keiser to Union Oil, 12/7/81, indicating that "...drilling mud is being disposed of by methods other than at the Sterling Special Waste Site and by methods that could possibly cause contamination of the ground water."

AK 01

State: Alaska

Region: 11

County/Parish: Kenai Peninsula

City/Town: Soldatna

Test of Proof: Administrative, Legal, and Scientific

Description

This case involves a 45-acre gravel pit on Poppy Lane on the Kenai Peninsula used since the 1970s for disposal of wastes associated with gas development. The gravel pit contains barrels of unidentified wastes, drilling muds, gas condensate, gas condensate-contaminated peat, abandoned equipment, and soil contaminated with diesel and chemicals. The property belongs to Union Oil Co. (UNOCAL), which bought it around 1968. Dumping of wastes in this area is illegal; reports of last observed dumping were in October 1985, as witnessed by residents in the area.

In this case, there has been demonstrated contamination of adjacent water wells with organic compounds related to gas condensate (ADEC laboratory reports from October 1986 and earlier). Alleged health effects on residents of neighboring properties include nausea, diarrhea, rashes, and elevated levels of metals (chromium, copper) in the blood of two residents. Property values have been effectively reduced to zero for residential resale. A fire on the site on July 8, 1981, was attributed to combustion of petroleum-related products, and the fire department was unable to extinguish it. The fire was allegedly set by people illegally disposing of wastes in the pit.

Fumes from organic liquids are noticeable in the breathing zone onsite. UNOCAL has been directed on several occasions to remove gas condensate in wastes from the site. Since June 19, 1972, disposal of wastes regulated as solid wastes has been illegal at this site. The case has been actively under review by the State since 1981.

Waste Analysis

A sample contained a series of compounds identified through gas chromatography as gas condensate. Onsite test wells have shown elevated levels of arsenic and other metals. Analysis indicated exceedences of EPA Drinking Water Standards for chromium, 0.17 mg/L; iron, 82 mg/L; and manganese, 1.5 mg/L.

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: Photos showing illegal dumping in progress. Field investigations. State of Alaska Individual Fire Report on "petroleum dump," 7/12/81. File memo on site visit by Howard Keiser, ADEC Environmental Field Officer, in response to a complaint by State Forestry Officer, 7/21/81. Memo from Howard Keiser to Bob Martin on his objections to granting a permit to Union Oil for use of site as disposal site on basis of impairment of wildlife resources, 7/28/83. Letter, ADEC to Union Oil, objecting to lack of cleanup of site despite notification by ADEC on 10/3/84. Analytical reports by ADEC indicating gas condensate contamination on site, 8/14/84. EPA Potential Hazardous Waste Site Identification, indicating continued dumping as of 8/10/85. Citizens' complaint records. Blood test indicating elevated chromium for neighboring resident Jessica Black, 1/16/85. Letter to Mike Lucky of ADEC from Union Oil confirming cleanup steps, 2/12/85. Memo by Carl Reller, ADEC ecologist, indicating presence of significant toxics on site, 8/14/85. Minutes of Waste Disposal Commission meeting, 2/10/85. ADEC analytic reports indicating gas condensate at site, 10/10/85. Letters from four different real estate firms in area confirming inability to sell residential property in Poppy Lane area. Letter from Bill Lamoreaux, ADEC, to J. Black and R. Sizemore referencing high selenium/chromium in the ground water in the area. Various miscellaneous technical documents. EPA Potential Hazardous Waste Site Preliminary Assessment, 2/12/87.

KS 14

State: Kansas

Region: 6

County/Parish: Sedgwick

City/Town: Witchita

Test of Proof: Legal

Description

In 1961, Gulf and its predecessors began secondary recovery operations in the East Gladys Unit in Sedgwick County, Kansas. During secondary recovery, water is pumped into a target formation at high pressure, enhancing oil production. This pumping of water pressurizes the formation, which can at times result in brines being forced up to the surface through unplugged or improperly plugged abandoned wells. When Gulf began their secondary recovery in this area, it was with the knowledge that a number of abandoned wells existed and could lead to escape of salt water into fresh ground water.

Gerald Blood alleged that three improperly plugged wells in proximity to the Gladys unit were the source of fresh ground-water contamination on his property. Mr. Blood runs a peach orchard in the area. Apparently native brine had migrated from the nearby abandoned wells into the fresh ground water from which Mr. Blood draws water for domestic and irrigation purposes. Contamination of irrigation wells was first noted by Mr. Blood when, in 1970, one of his truck gardens was killed by irrigation with salty water. Brine migration contaminated two more irrigation wells in the mid-1970s. By 1980, brine had contaminated the irrigation wells used to irrigate a whole section of Mr. Blood's land. By this time, adjacent landowners also had contaminated wells. Mr. Blood lost a number of peach trees as a result of the contamination of his irrigation well; he also lost the use of his domestic well.

The Bloods sued Gulf Oil in civil court for damages sustained by their farm from chloride contamination of their irrigation and residential wells. The Bloods won their case and were awarded an undisclosed amount of money.

Waste Analysis

Water samples from wells owned by Mr. Blood showed chloride concentrations of 977 and 765 ppm in 1962. In 1970, the two wells showed chloride concentrations of 1,570 and 1,730 ppm.

Comments

API states that damage in this case was brought about by "old injection practices".

Violation of State Regulations: No

Documentation

References for case cited: U.S. District Court for the district of Kansas, Memorandum and Order, Blood vs. Gulf; Response to Defendants' Statement of Uncontroverted Facts; and Memorandum in Opposition to Motion for Summary Judgment. Means Laboratories, Inc., water sample results. Department of Health, District Office #14, water samples results. Extensive miscellaneous memoranda, letters, analysis.

TX 11

State: Texas

Region: 7

County/Parish: Runnels

City/Town: Miles

Test of Proof: Administrative and Scientific

Description

In West Texas, thousands of oil and gas wells have been drilled over the last several decades, many of which were never properly plugged. There exists in the subsurface of this area a geologic formation known as the Coleman Junction, which contains extremely salty native brine and possesses natural artesian properties. Since this formation is relatively shallow, most oil and gas wells penetrate it. If an abandoned well is not properly plugged, the brine contained in the Coleman Junction is under enough natural pressure to rise through the improperly plugged well and to the surface.

According to scientific data developed over several years, and presented by Ralph Hoelscher, the ground water in and around San Angelo, Texas, has been severely degraded by this seepage of native brine, and much of the agricultural land has absorbed enough salt as to be nonproductive. This situation creates a hardship for farmers in the area. The Texas Railroad Commission states that soil and ground water are contaminated with chlorides because of terracing and fertilizing of the land. According to Mr. Hoelscher, a long-time farmer in the area, little or no fertilizer is used in local agriculture.

Waste Analysis

Analysis of Ralph Hoelscher's domestic water well indicated sodium at 334 ppm, calcium at 359 ppm, strontium at 3.4 ppm, sulfate at 191 ppm, chloride at 980 ppm, nitrate at 229 ppm, and total dissolved solids of 2,479 ppm. Soil analysis on a portion of the Hoelscher farm revealed chloride at 10,000 ppm, sodium at 6,440 ppm, magnesium at 1,302 ppm, and calcium at 15,400 ppm.

Comments

None.

Violation of State Regulations: Yes

Documentation

References for case cited: Water analysis of Ralph Hoelscher's domestic well. Soil Salinity Analysis, Texas Agricultural Extension Service - The Texas A&M University System, Soil Testing Laboratory, Lubbock, Texas 79401. Photographs. Conversation with Wayne Farrell, San Angelo Health Department. Conversation with Ralph Hoelscher, resident and farmer.

TX 15

State: Texas

Region: 7

County/Parish: Tom Green

City/Town: San Angelo

Test of Proof: Scientific

Description

In the 1950s, oil was discovered in what is known as the Yankee Canyon Field, Texas, producing from the Canyon Sand at about 4,000 feet. In 1958, the field was converted to the water flood secondary recovery process. More than 50 wells were drilled in this field with only 12 to 15 of the wells producing while the balance of the old wells remain unplugged and abandoned. One well is located on a farm owned by J.K. Roberts and is about 200 yards from his 70-foot deep domestic water well. Chlorides in his well have climbed from 148 ppm in 1940 to 3,080 ppm in 1970. Mr. Hoelscher believes that the unplugged abandoned well 200 yards from Mr. Roberts' water well is allowing migration of salt water into the freshwater aquifer. Responding to pressure from the local media and from Mr. Hoelscher, the Texas Railroad Commission performed remedial work on a number of wells in the field in the 1980s.

Waste Analysis

Roberts' water well showed a chloride concentration of 148 ppm on 11/11/40, 3,080 ppm on 5/22/70, and 3,120 ppm on 4/29/84.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Letter from J.K. Roberts of 259 Robin Hood Trail, San Angelo, Texas 76901, to U.S. Army Engineer District, Major C. A. Allen, explaining the water well contamination; enclosed with letter are sampling results from the water well. SW Laboratories, sampling reports from 6/8/70. Letter from E.G. Long, Texas Water Quality Board, to L.D. Gayer, attorney for Mr. Roberts, explaining that case will be forwarded to the Texas Railroad Commission. Letter and sampling report from F.B. Conselman, consulting geologist to W. Marschall, explaining sample results and recommendations.

LA 65

State: Louisiana

Region: 4

County/Parish: Concorida

City/Town: Ferriday

Test of Proof: Legal and Scientific

Description

Crow Farms, Inc., the operator of the Angelina Plantation in Louisiana, initiated a $7 million civil suit against operators of active and abandoned oil test wells, oil production wells, and an injection well, for allegedly causing progressive loss of agricultural revenue because of native brine contamination of ground water used to irrigate 1.7 square miles of rice, soybeans, and rye. Analysis of the site by private technical consultants concluded that it will take 27 years to restore the soil and a longer period to restore the aquifer.

At least seven wells have allegedly affected the ground water in the area, including two active oil production wells, both operated by Smith, Wentworth and Coquina, and five abandoned oil test wells drilled by Hughes & New Oil Co. An extensive study conducted by Ground-Water Management, Inc., concluded that Crow Farms, Inc., used irrigation wells contaminated by brine water from the oil-producing formation. Crow Farms, Inc., engaged Donald O. Whittemore of the Kansas Geological Survey to chemically "fingerprint" the wastes and confirm that the brines in the irrigation water originated in the oil-producing formation. This brine traveled up unplugged or improperly plugged wells or down the annulus of producing wells, leaking into the freshwater aquifer used for irrigation, thereby contaminating the aquifer with chloride levels beyond the tolerance levels of the crops. Records of the case state, "Surface casings may not have been properly cemented into the Tertiary clays underlying the alluvial freshwater aquifer. If these casings were not properly cemented, brine could percolate up the outside of these casings to the freshwater aquifer at an oil or gas well test location where improper abandonment procedures occurred. Any brine in contact with steel casings will rapidly corrode through the steel wall thickness gaining communication with the original bore hole."

Crow Farms has spent in excess of $250,000 in identifying the source of ground-water degradation. The case is pending.

Waste Analysis

Contaminated irrigation wells were compared to nearby uncontaminated wells over a 5-year period. Test wells were also drilled for comparison. Chlorides in contaminated wells ranged from 341 to 3,200 mg/L. Background chloride levels registered between 30 and 100 mg/L in the area. Conductivity was found to average 3.6 umhos for contaminated wells and 0.81 /mhos for background wells. The sodium-adsorption ratio (SAR) tests showed an average of 44.6 for contaminated wells and 7 for background wells. Resistivity testing of the irrigation aquifer found high brine concentration levels in areas around wells suspected of being a contamination pathway to the aquifer.

Comments

Comments in the Docket from Louisiana's Office of Conservation pertain to LA 65. The Office of Conservation states that "...the technical evidence that has been gathered and is being presented by Angelina is currently being refuted by technical evidence that was gathered on behalf of the defendant oil companies." One defendant oil company hypothesizes that "...Bayon Cocodine was the source of the contamination based on a review of data presented by Angelina at the hearing." Another defendant oil company states that "...salt water was present, as an occurrence of nature in the base of the Mississippi River Alluvial Aquifer....Excessive pumpage could result in upcoming, bringing this salt water to the surface."

Violation of State Regulations: No

Documentation

References for case cited: Brine Contamination of Angelina Plantation, Concordia Parish, Louisiana by Groundwater Management, Inc.; includes extensive tables, testing, maps, figures, 8/25/86. Geochemical Identification of the Salt Water Source Affecting Ground Water at Angelina Plantation, Concordia Parish, Louisiana, by D. O. Whittemore, 4/86. Calculated Chloride Distribution and Calculated Plume, Soil Testing Engineers, Inc., 1986.

NM 03

State: New Mexico

Region: 9

County/Parish: San Juan

City/Town: Flora Vista

Test of Proof: Administrative and Scientific

Description

The Flora Vista Water Users Association, Flora Vista, New Mexico, operates a community water system that serves 1,500 residents and small businesses. The Association began operation of the system in 1983 with two wells, each capable of delivering 60 to 70 gallons per minute. In 1980, Manana Gas, Inc., drilled the Mary Wheeler No. 1-E, and began producing natural gas and oil on a production site less than 300 feet from one of the Flora Vista water wells. In 1983, one Flora Vista water supply well became contaminated with oil and grease, allegedly by the Manana Gas well, and was taken out of service. After extensive testing and investigation, the New Mexico Oil Conservation Division concluded that the Manana Gas well was the source of oil and grease contamination of the Flora Vista water well. The Conservation Division investigation included water analysis on affected water wells and on five monitoring wells as well as pumping tests to ascertain the source of the contamination. Although the gas well lies downgradient from the water well, it was demonstrated that pumping of the water well drew the oil and grease upgradient, thus contaminating the water well. Water now has to be purchased from the town of Aztec and piped to Flora Vista. There is no indication in reports that the production well responsible for this contamination has been shut down or reworked to prevent further contamination of ground water. The State asserts that very recent work done at the site has determined the source of contamination to be a dehydrator located near the production well.

Waste Analysis

Water analysis was done on water wells affected as well as on five monitor wells. Analysis shows hydrocarbon contamination of ground water; methane was found at 1,200 times the ambient levels. Pumping tests were also done to ascertain the source of pollution. Although the gas well lies downgradient from the water well, it was demonstrated that pumping of the water well drew the oil and grease upgradient, thus contaminating the water well.

Comments

Comments in the Docket by the Governor of New Mexico pertain to NM 03. The Governor states that the case incorrectly cites the gas well as the source of hydrocarbon contamination and comments that another OGC report specifically eliminated the gas well because of "...fully cemented surface casing extending to a depth of over 220 feet." The New Mexico Oil and Gas Commission is still investigating the source of contamination.

Violation of State Regulations: No

Documentation

References for case cited: Final Report On Flora Vista Contamination Study, October 1986, prepared by David G. Boyer, New Mexico Oil Conservation Division. Water analysis results of the Flora Vista Well field area.

NM 04

State: New Mexico

Region: 9

County: Lea

City/Town: Hobbs

Test of Proof: Administrative and Scientific

Description

Lea County, New Mexico, has been an area of major hydrocarbon production for a number of decades. Oil field contamination of freshwater sources became apparent as early as the 1950s. Contamination of the freshwater aquifer has resulted from surface waste pit seepage and seepage from production and injection well casings. Leakage of oil from oil production well casings has been so great in some areas as to allow ranchers to produce oil from the top of the Ogallala aquifer using windmill pumps attached to contaminated water wells. Approximately 400,000 barrels of oil have been pumped off the top of the Ogallala aquifer to date, although production is decreasing because of repairs of large leaks in oil production wells. Over 120 domestic water wells in the area have been so extensively contaminated with oil and brine as to preclude further use of the wells for domestic or irrigation purposes. Many residents have been using bottled water for a decade or more as a result of the contamination.

Waste Analysis

Water analysis performed on numerous Hobbs private water wells showed the following high levels of contaminants: chloride, 1,947 mg/L; total dissolved solids, 3,742 mg/L; and benzene, 0.004 mg/L.

Comments

None.

Violation of State Regulations: No

Documentation

References for case cited: Sampling data from residential wells in Ogallala aquifer in Lea County, N.M. Report: Organic Water Contaminants in New Mexico, by Dennis McQuillan, 1984. Windmills in the Oil Field, by Jolly Schram, circa 1965.

AK 09

State: Alaska

Region: 11

County/Parish: Storkersen Point

City/Town: Not Applicable

Test of Proof: Scientific

Description

From 1971 to 1975, a study was done for the Department of the Interior by individuals from Iowa State University concerning water birds, their wetland resources, and the development of oil at Storkersen Point on the North Slope of Alaska. The area is classified as an arctic wetland. Contained in the study area was a capped oil well (owner of well not mentioned). Adjacent to the capped oil well was a pond that had been severely polluted during the drilling of this well. Damage is summarized in the study as follows:

"The results of severe oil pollution are indicated by the destruction of all invertebrate and plant life in the contaminated pond at the Storkersen Point well; the basin is useless to water birds for food, and the contaminated sediments contain pollutants which may spread to adjacent wetlands. Petroleum compounds in bottom sediments break down slowly, especially in cold climates, and oil-loaded sediments can be lethal to important and abundant midge larvae, and small shrimp-like crustaceans. Repopulation of waters over polluted sediments by free-swimming invertebrates is unlikely because most aquatic invertebrates will be subjected to contact with toxic sediments on the bottom of wetlands during the egg or overwintering stage of their life cycle. Unfortunately, human-induced change may create permanent damage before we can study, assess, and predict the complications. First order damage resulting from oil development will be direct effects of oil pollution on vegetation and wetland systems. Oil spills almost anywhere in this area where slopes are gradual and drainage patterns indefinite, could result in the deposition of oil in many basins during the spring thaw when melt water flows over the impermeable tundra surface. Any major reduction of food organisms through degradation of preferred habitats by industrial activity will be detrimental to local aquatic bird populations."

Waste Analysis
Not Available.

Comments
None.

Violation of State Regulations: No

Documentation

References for case cited: Water Birds and Their Wetland Resources in Relation to Oil Development at Strokersen Point, Alaska, United States Department of the Interior, Fish and Wildlife Service, Resource Publication 129, 1977.